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Master Thesis

Modelling power markets coupling with Matlab

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Thomas Sarigiannis

July, 2021

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Abstract

The dawn of 21st century has found the energy sector in a transition phase. The liberalization of the industry has forced the, once powerful State-owned, companies to abandon their single-integrated model and adopt a new state of competition, in every part of the sector. Thus, energy companies would begin to compete with each other in generation, retailing, transmission and distribution. Countries would find themselves adopting different models, based on their desirable benefits, with the most popular one consisting of independent transmission and distribution operators (TSO and DSO) which coordinate market operation. With the European Green Deal in effect and the de-carbonization shift in progress, Europe aims to interconnect all electricity market, integrating into a single market. The process of market coupling will achieve price convergence between members, as well as maximize exploitation of decentralized renewable energy sources. The structure of the Thesis is as follows:

- In the first chapter, the operation of an electricity energy market is analyzed. The technical specifications of an electricity system are defined, followed by the different market models adopted in the industry.
- In the second chapter, the scope of market coupling is discussed. At first, the benefits of this process are explained, along with the algorithm of its implementation. Finally, the two coupling models are described, Available Transfer Capacity or Net Transfer Capacity, and Flow-Based market coupling.
- In the third chapter, a simulation of the Available Transfer Capacity model is performed. Two regions, A and B, are coupled in four scenarios with varying transmission capacity. The resulting prices as well as other comparison data are presented in figures and tables.

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1. Operation of the electricity energy market

1.1. The electricity system

Electricity systems in most countries around the world consists of two parts: the physical infrastructure and the electricity market. Both of these parts work together, so that businesses and households enjoy access to electricity for their everyday needs.

The physical infrastructure consists of electricity generator and transportation systems that connect production with consumption. Electricity is generated by production units, which include many different technologies. Conventional units make use of thermal energy from fossil fuels (coal, oil, natural gas) and convert it to electricity. Other units such as hydropower

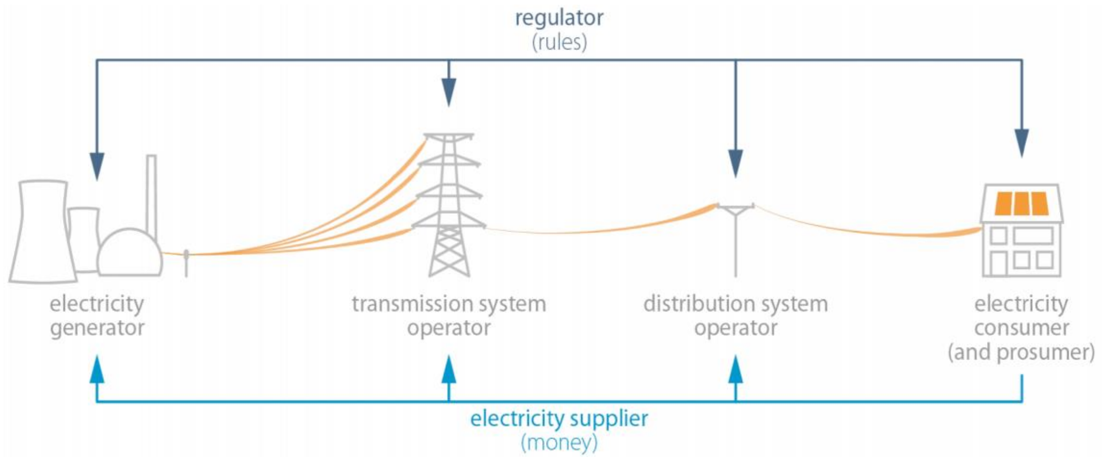

Figure 1.1 Overview of the electricity system. [1]

plants, wind farms and solar farms utilize natural elements such as water, wind and sun for their production. The electrical grid transport electricity from producers to consumers. The transmission system is responsible for electricity travelling long distances in order to reach residential and industrial areas. Then, the distribution system connects all consumers and supplies them with produced electricity from generators. [1]

The electricity market, also known as Power exchange market, is the place where electricity is wholesale-priced. It is a centralized mechanism for producers to sell the electric energy they produce to other participants, that serve the role of retail providers to consumers. Exchanges in the energy market offer transparency between participants, as all transactions are visible and prices are determined by offer and demand quantities, while taking into consideration constrains for the network's operation. Power markets offer protection to consumers and incentivize producers to increase their investments in the sector, as they are the ones making the profit in exchanges. In general, the electricity market can be separated into two different markets: energy and capacity market. They are closely interdependent and their operations connected. Despite that, not all countries operate both energy and capacity markets. [2]

1.2 Grid Constrains

For the electricity market to function properly, the power exchange mechanism must respect the technical properties of the electric grid. The two properties that influence the market the most, are supply and demand, and electricity flow. Electricity production must always match demand at all times. This requirement is related to the grid frequency, which must remain stable, with minimal fluctuation. Lower production than demand can cause blackouts, while higher production will destabilize the grid and potentially damage industrial machines, devices and other electrical appliances. The electricity flow follows the past of least resistance, meaning that energy flows from production to consumption [1]. Additionally, limits exist on the maximum flow across the grid. Current flow causes heating and electrical cables of transmission and distribution networks have thermal limits. Therefore, the maximum energy flow is limited by the maximum temperature the cable can sustain, before it is damaged. Voltage values must also remain within limits, and to ensure system stability, reactive power monitoring is necessary. [3] These requirements are met by balancing supply and demand using reserves. The reserves consist of generator units that can enter production within seconds, few minutes, or quarter of hour. Since reserves are needed in hours of higher demand, companies may adopt strategies to use their power plant at those intervals, where pricing is higher. Finally, bigger shares of renewables in the energy mix increase the uncertainty factor of supply, causing more risk for unbalanced supply and demand. [1]

1.3 Market Structure

Not all countries adopt the same structure for their electricity industry. The first years of the industry were dominated by single integrated companies, acting as monopolies and most of them owned by the State. Following the liberalization of economies, the electricity market has also evolved. There is now competition in all parts of the industry through formal markets [3]. The liberalized electricity market consists of generators, who sell electricity, and suppliers, who purchase from generators and sell to consumers. Transmission system operators (TSO) are responsible for transporting energy across long distances and securing network stability, while distribution network operators (DSO) ensure that energy is delivered to consumers. Finally, a regulatory authority sets market rules and monitors operation [1].

A major step forward towards real market competition was the idea of an independent system operator (ISO), that manages a centralized spot market. It operates in real-time and is open to all participants in transparent and heavily regulated competition. Since the grid is considered a natural monopoly [3], TSOs manage it as an asset, charging a non-discriminatory fee to all participants for its use and a service fee for operating the market, as incentives for system development and efficient operation [4].

1.4 Electricity Market models

1.4.1 Single-buyer Model

The single-buyer model made its first appearance during 1990s, where developing countries were in search of a market model for their electricity market. In this model, the government plays the main role through its national power company. Private investors are encouraged to invest in generator capacity, building new power plants and selling generation to a single entity at the lowest cost, which is the national company and the single buyer. This would be achieved through purchase agreements between all private generators and the national company, including take-or-pay quotas or fixed capacity charges, so as to protect private investments from market risk. Some countries would even take a step further, splitting the national company into generation, transmission and distribution companies and offer them premium rights, as they act as a single buyer, purchasing exclusively from producers and selling to distributors. This unbundling is promising in terms of improving competition, because it treats all independent power producers equally as bilateral contracts with distributors are not possible, that would otherwise favor some producers. Though the hold-up problem remains, where the single buyer will change market arrangements, after an investment has been made in generation by a private investor.

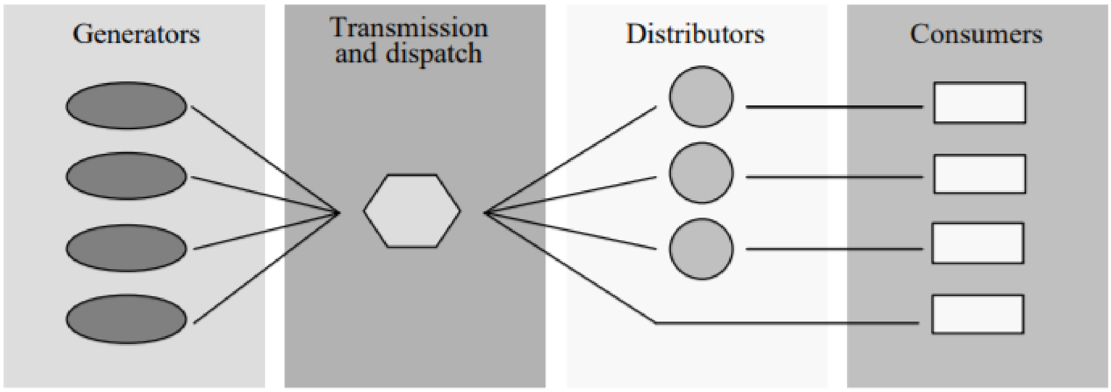

Figure 1.2 The single-buyer model. [6]

The popularity of the model is due to economic, technical and institutional benefits it offers. The presence of a single entity responsible for buying and selling electricity, provides a safety factor to grid operation. While demand must always match production physically, this entity can achieve load balancing in the market. It also provides more risk safety to investors in production, encouraging them to increase capacity in the future and maintains a unified wholesale electricity price. However, the presence of the national company predisposes a state's favor towards it, as well as future governmental interventions in order to elevate the company's interests or impose regulations influenced by political decisions to satisfy public opinion. In the end, the single-buyer model is the market pre-stage for countries, that do not wish to follow a liberalized market approach. [5]

Improvements can be made, so as to negate the disadvantages of this model. In its most advanced for, the single-buyer model adopts the mandatory pool, that replaces purchase agreements with the single entity. Governments guarantees no longer offer risk safety to generators and prices react to demand and supply changes.

1.4.2 Power pools

Power pools were established to utilize all available electric utilities, resources and interconnections, in order to jointly manage power flows and improve economic efficiency. In a power pool, generators submit their offers in electric energy they are willing to produce to the grid. Each offer is accompanied by a price bid per energy unit. On the demand side, an entity operates as a market operator and forecasts the demand in electricity. Usually, this is performed by an Independent System Operator, which operates the transmission system, while also acting as a broker, purchasing from generators and selling to retailers. Dispatch of generating units can also be made according to a demand curve, which is formed by bids of buyers on the wholesale market, such as distribution companies [7]. In a power pool, producers and buyers are required to submit their bids on a daily basis, ahead of the corresponding time frame they have chosen to make their offers.

Demand and supply is matched and a form of auction takes place, selecting generating units in merit order. During this process, a single energy price is calculated for an area and the cheapest generators below this price receive priority. The overall solution is then examined, if it satisfies grid constraints and how much congestion it causes. Some markets relieve congestion by dispatching out-of-merit generators, eventually adding an extra charge in price for this purpose. Others adopt a model that allows Locational Marginal Pricing (LMP), which refers to the cost of supplying energy at a specific location of the network. Consequently, there is no uniform price for the whole grid, but instead a different price per location, either as a node price or a wider zone price. With this approach, the cost of congestion burdens market participants that cause it and not the whole market, as in the previous case.

A power pool model with Locational Marginal Pricing in a nodal configuration represents an ideal market. Prices in nodes reflect all costs of supplying electricity at each specific node, and thus manage congestion at the same time. When new generation capacity enters the network, or transmission lines are upgraded, it instantly sends a signal to market participants regarding the location, as prices in nearby nodes are affected. This pricing scheme can also be expanded into larger areas, called zones, which contain multiple nodes. However,

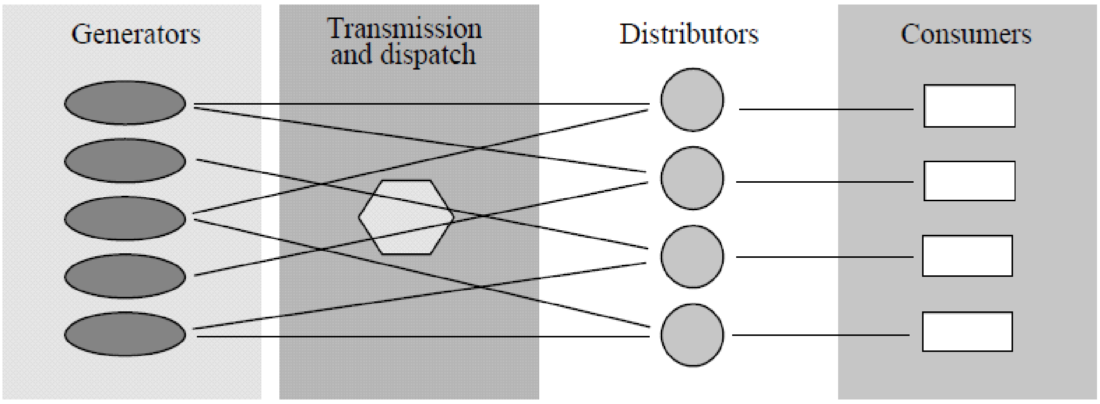

Figure 1.3 The power pool market model. [6]

the zonal prices do not always represent nodal ones. If congestion happens inside a zone, nodes receive different prices according to network characteristics, however the zone price will not be affected. Although the zonal approach burdens the participants with the congestion costs, the market enjoys increased liquidity and greater competition [7]. Nodal pricing models are mainly used in the United States electricity markets, while the European region adopts zonal pricing. [2]

1.4.3 Bilateral Contracts

Another model, alternative to power pool, is a market mechanism that offers physical bilateral contracts between participants. It allows sellers and buyers to enter into transactions between them freely, and negotiate power supply contracts. Normally, one could say that generators will have the role of sellers and retail companies the one of buyers. This is not binding, though. Generators could also buy energy from another producer to cover any shortage in generation they have and satisfy their contracts. Similarly, retail companies can sell energy to other companies, acting as a brokers [4]. These transactions are known as Over the Counter (OTC) transactions and parties decide contract terms among each other, without the presence of a central entity. Despite the increased freedom offered, there would always be a difference between volumes agreed through contracts and actual volumes physically delivered. For this reason, the system operator will have to calculate these differences and diminish them so as to match demand and supply in real-time. Therefore, the operator runs a balancing market where a price is settled for imbalanced supply of energy. Some countries operate a power exchange in parallel with bilateral contracts model. This hybrid model has been operating in many European countries such as Netherlands (Amsterdam Power eXchange), France (Powernext), Scandinavia region (NordPool), Poland (PolPX) and Austria (EXAA). Others are even operating multiple exchanges such as Germany (EEX and LPX) and England (UKPX, APX, PowerEX and IPE).

Power pools and bilateral contracts are two equivalent electricity market models. However, when taking into account transactions, power pools provide a more optimal outcome because electricity price and quantity reflect demand and supply in real-time, depending on how far transacted quantities refer to. They offer increased price transparency and transactions are anonymously. Though, setting up such a mechanism is more expensive and more utilities are necessary due to volatility of prices in power exchanges. [7]

1.5 Market Clearing Parameters

Market clearing can be made under many approaches, according to the utility the electricity market is performing exchanges for. The electricity market runs exchanges for markets such as the day-ahead market, hour-ahead market or real-time (also known as balancing market). In the day-ahead market, prices are cleared hourly for each next day, for each zone/node in the network. Therefore, there can be 24 different network topologies for each day, depending on available generators, demand and supply bids and scheduled contracts. In order for the clearing process to calculate the optimal dispatch solution for units, specific parameters are required as inputs. Such inputs are electricity demand, generating plant characteristics, transmission network characteristics and various constraints and restrictions.

Electricity demand is calculated based on a forecast, taking into consideration previous annual statistical data on load demand during specific hours, bids made by participants and scheduled transactions from contracts. Each power plant has its own cost profile, depending on generation technology used. Some cost factors that influence their price bids are:

-Energy cost: Units that rely on thermal energy for their generation, such as coal-fired power plants, gas or diesel turbines must account on production cost, which is fuel and efficiency rates.

-Start-Up Cost: Another important factor is the cost of transitioning from offline to online state. Each plant has a different cost curve, based on three parameters: Cold start, intermediate start and hot start. Also, the time required to transition between those states varies, and generators should submit those times.

-Minimum Load Cost: The minimum load cost refers to the operating cost of the unit, while operating at minimum load possible, depending on generator design.

The computer software which performs the market clearing process and assigns generating schedules also receives input information, regarding units' characteristics, as well as network security parameters that the system operator considers necessary. Among units' characteristics are operational constraints, such as thermal limits and minimum and maximum levels of dispatchable energy production, in case of emergency. Ramp rates are also important, as they reflect the time each unit requires to move between different production points. Other parameters included are the available capacity reserve of each unit, which the system takes into account, in the event of loss of a dispatched unit or transmission line. Finally, producers should also submit the minimum run and down time of their units, so dispatch schedules for consecutive hours are calculated more efficiently. [2]

2. Coupling of markets

2.1 Scope of market coupling

Following the process of market liberalization, structural developments and changes in institutions have reshaped the energy markets in European and North American region, affecting the interaction of supply and demand and general price formation. A major impact was the introduction of renewable energy sources in the generation mix, with the location of their sites being a challenge to market integration. Renewable generation sites are decentralized, spread out in the countryside, away from centers of demand. Also, depending on the generation technology and terrain characteristics, some sites are concentrated in specific regions. For example, in the North Sea, wind farm penetration in the energy mix is very high. On the other, the American state of Arizona, with the most sunny days annually and its vast land, dominates in solar panel generation. Additionally, the volatility in production of some renewable sources, as well as their intermittable operation proves demanding for Transmission system operators in forming an integrated network.

With the European Green Deal in effect, the Union aims to establish an internal electricity market, an initiative to integrate European electricity markets into a single one. The goal is to form a network between all European countries, so that energy generated from renewables flows towards demand across the whole region, instead of congesting within national markets. Along with the transfer of energy, achieving full price convergence in electricity is also of interest. Very high price differential between markets that have cheaper generating units and those with more expensive ones, can be detected in the European region [8]. In turn, substantial investments in transmission infrastructure are necessary to increase cross-border capacity between each European member, enough to ensure that excessive generation flows to demand. However, a proper market model which provides access to cross-border capacity is equally important. It should not discriminate among market participants that wish to cross-trade, and at the same time respect network characteristics.

In order to implement efficient cross-border electricity trading, a mechanism that calculates and allocates capacity is required. Coordination across all bidding zones between different national markets is essential, since flow of electricity is not directed by commercial agreements in the market, but by the laws of physics [9]. The existing situation in cross-border trading is far from perfect, as the clearing of electricity spot market and capacity market happens at a different time sequence. This forces participants that wish to trade, to acquire transmission capacity for a given direction, before electricity spot prices in the two regions are determined. Eventually, traders can only anticipate direction and capacity based on forecasted data, and taking into consideration the volatility of spot markets, they may end up trading from a high price region to a lower price one. Since this phenomenon is against the concept of price convergence within a single market, this allocation practice is slowly being replaced by the simultaneous clearing of both spot and capacity markets, which results in overall efficient of cross-border power flows. [10]

2.2 Capacity Allocation

Generally, the mechanism of explicit allocation is widely implemented, mainly due to the fact that such a mechanism can be set up fairly easy and quickly, without any institutional harmonization between adjacent markets. Capacity markets are separated from spot markets, hence not much coordination and integration is required between transmission system operators and power exchanges. Creating a uniformed trading platform with common exchange rules is not a necessity. Explicit allocation offers the possibility to acquire physical transmission rights via auctions for different frame times, like annually, monthly or even daily. However, the absence of simultaneous closing of both markets offers poor results in operation of transmission lines, as they are not being used to the maximum limits of their transmission capability or are forced to flow energy adversely to physical flow. [11]

Contrary to the above concept, market coupling clears both markets at the same time by implicitly allocating transmission rights within the spot auctions. Firstly, the system clears the market price determined by total demand and supply. Both national markets are cleared as one, ignoring capacity constraints. If no congestion appears, all areas have a single price. Otherwise, multiple pricing zones are formed, depending on network bottlenecks. Daily, the system operator calculates the remaining capacity available for cross-border trade, which is not allocated explicitly by traders, and is assigned to the power exchange. Then, a joint algorithm determines the optimal cross-border quantities in order to achieve a price convergence. To achieve such optimal result, the system aims at solving the problem of maximizing overall welfare. The algorithm does not always achieve a price convergence, which is constrained by maximum transmission capacity between two national markets. As a result, the price difference, known as congestion rent, is acquired by the owner of the interconnection. [12]

2.3 Market coupling algorithm

The problem of market coupling is an optimization problem: all orders, demand and supply, from different exchanges must be matched in such a way, that the maximum total gains from trade are achieved. This means that the lowest-priced supply orders are matched with the highest-priced demand orders. Traded volumes on different markets are not required to be equal, as long as they are even in total and cross flows are feasible. Additionally, its complexity must also be taken into consideration. These orders refer to exchanges that come from not a single network, but separate networks with different characteristics. In this case, all involved Independent System Operators have pre-determined, in co-operation, the topology and capacities of a simplified network through system analysis and simulation. [13]

Once all participants' bids are submitted, the welfare maximization problem, which is defined as the cumulated differences between willingness to pay and accepted prices in the bidding process, and is formulated as follows:

$$\max_{q} \sum_{r \epsilon R} \left(\sum_{i \epsilon I_r} q_i P_i - \sum_{j \epsilon J_r} q_j P_j \right)$$

where:
$\boldsymbol{r} \in \boldsymbol{R}$ are the regions under study,
$\boldsymbol{i} \in \boldsymbol{I_r}$ are the demand bids in each region **R**,
$\boldsymbol{j} \in \boldsymbol{J_r}$ are supply bids in each region **R**,
$\boldsymbol{P_{i,j}}$ are the price of demand and supply bids in the region,
$\boldsymbol{Q_{i,j}}$ are the quantities of demand and supply bids in the region,
$\boldsymbol{q_{i,j}}$ are the accepted quantities in the region

Constraints are applied to the accepted volumes, making sure that they do not exceed the quantity of an order:

$$q_i \leq Q_i$$
$$q_j \leq Q_j$$

Additionally, accepted quantities q_i and q_j must satisfy the following condition:

$$\sum_{i \in I_r} q_i - \sum_{j \in J_r} q_j = C_{r_a, r_b}$$

where $\boldsymbol{C_{r_a, r_b}}$ is the actual capacity used between two regions a,b. As the maximum available capacity for trading cannot exceed the interconnector capacity, $C_{r_a, r_b} \leq Cap_{r_a, r_b}$
where $\boldsymbol{Cap_{r_a, r_b}}$ is the interconnector capacity. Solving the optimization problem outputs an optimal usage of interconnector capacities. Prices are then computed by considering the highest prices of supply bids and the lowest prices of demand bids for each region. However, this approach is quite simplified. In the case of block-orders, which include bids for multiple hours, the problem becomes quite challenging. Because those bids cannot be partially accepted, the problem becomes from a linear one, to a mixed integer linear problem, which

require increased computational effort to solve. Along with this, the time pressure of clearing the market before a deadline exists.[14]

To achieve market integration, more progress must be made in managing congestion at interconnections between regions that perform cross border trading. Picture 1 displays the price-quantity curves of two electricity market regions, A and B, that have available interconnections between them. In graph a. , the interconnector between the two regions is not used and each market clears at its own equilibrium point. Such a situation, in which prices are different, offers an opportunity for arbitrage for traders to buy electricity in Region B, where the price is lower, and sell to Region A with higher price. Under perfect competition, transfer of energy would happen from B to A, until prices are equal between the regions or the capacity is used at its maximum. In Figure 1b, the interconnector is used with enough capacity for exchanges. In this case, prices for both regions converge to a single price. In Figure 1c, interconnector capacity is limited, and as a result prices cannot fully converge and a price difference exists. This difference is called congestion rent and displays the value of interconnection capacity as a scarce resource. [14]

Efforts today mainly focus on managing congestion at cross-border connections connecting multiple markets, where each area relates to one Transmission System Operator. Leaving the task of capacity allocation to the current situation in the market, of separate

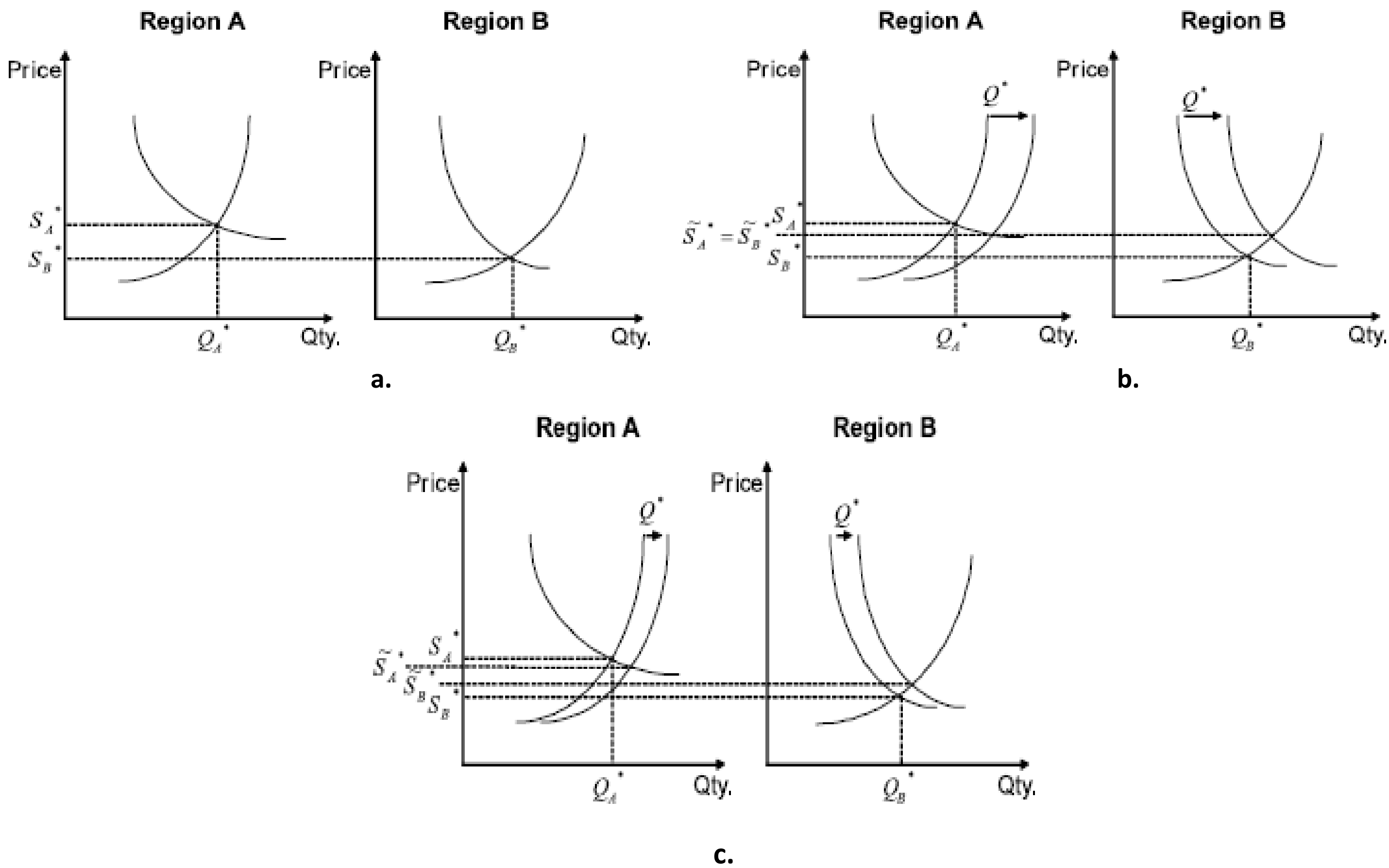

Figure 2.1 Demand and Supply curves of two regions, A and B, with available interconnector: a) interconnector is not used, b) interconnector is used, with sufficient capacity, c) interconnector is used, but capacity is limited. [14]

capacity and day-ahead auctions, causes inconsistencies and often leads to sub-optimal result. As power markets cannot be designed all over again, the existing structure must be used. As a result, each market is different, and different coupling models are applied between them. The most integrated model is price coupling, where both prices and flows are computed by a centralized system. Bids are forwarded to the coupler and volumes with prices are received in return [15]. However, difficulties arise when two regions, which operate their own coupling methods, need to be connected. [16]

2.4 Coupling Models

2.4.1. Available Transfer Capacity (ATC) and Net Transfer Capacity (NTC)

The first coupling model was proposed in 2003 by the European Transmission System Operators (ETSO) and is known an "Coordinated Auctioning". It is a method that explicitly auctions Cross Border Transfer Capacities (CBTCs) [17] and can allocate capacities considering the different organization of national markets and the meshed structure of large electricity networks. The main drawback of the explicit auction is its poor efficiency in allocating transmission capacity, because auctions don't take place simultaneously for connected regions. Instead, an implicit method is used which allocates directly after the national markets, but it requires coordination between involved markets. To facilitate coordination, ETSO and the European Power Exchangers (EuroPEX) have proposed another method known as "Decentralized Market Coupling", where CTBCs are allocated by a centralized market. [18]

ATC and NTC models are a useful tool for market participants to anticipate cross-border demand, as well as for TSOs to plan management of electricity exchanges. In European region, TSOs calculate and publish transfer capacities for their area of responsibility and neighboring regions. Twice a year, ETSO publish a table with indicative values for Net Transfer Capacities (NTC) for the EU area. In order to calculate NTC, a series of extensive studies of load flows must be performed for all interconnected transmission systems. In the first place, the Total Transfer Capacity (TTC) is measured. TTC represents the maximum power that can be transmitted between two systems, reliably and without affecting network security. It is limited by the physical characteristics of the transmission lines under which they can operate without risk. These include the maximum current flow without overloading, the quality of supplied voltage and other limits to ensure stability.

To determine the TTC, the power exchanges between the two systems must be modelled and simulated. To perform this process ex ante market clearing, the simulation uses expected network configuration, multiple scenarios for cross-border exchanges and load demand, while shifting generation between the regions to create flows. Another parameter calculated is the Transmission Reliability Margin (TRM). TRM represents the uncertainty in forecasting power flows, due to incomplete market information from players and random events. Both can be regarded as probabilistic events, so TSOs evaluate it based on historical data or by using statistical methods. Then the Net Transfer Capacity is given by the following equation:

$$NTC = TTC - TRM$$

The value represents the maximum interconnector capacity, which can be used, in respect to physical constraints and uncertainties on future conditions. For each cross-border interconnection, two values are calculated for each direction of flow. When simulating generation increase in Region 1 and decrease in Region 2, the result is the value of $NTC_{1\text{-}2}$. When shifting to the opposite direction, $NTC_{2\text{-}1}$ is calculated. [19]

In the case of meshed networks, such as transmission systems on the European region, cross-border exchanges between two countries also cause flows in nearby connected regions, without any transactions taking place. According to laws regarding flow of electricity, electric current prefers the path of least resistance, resulting in additional flows through third countries before power is delivered to the destination. These flows are known as "parallel flows". Figure 2 represents countries of European region in a simplistic way. An export transaction of 100MW from Italy to Belgium results in 100MW increase in generation in Belgium and 100MW decrease in Italy. Due to parallel flows, nearby countries experience usage of their transmission system and interconnections, even though they are not physically connected with Italy. Therefore, NTC values in such networks heavily depend on realistic exchange scenarios used in the simulation. Precise values for the whole Internal Energy Market, where thousands of exchanges take place, a massive number of combinations would need to be analyzed by the TSOs. To give a representative picture of the interconnection capacity, though, they publish forecasted NTC values for pair of regions, between two countries, ignoring the effects on other regions. Thus, values are mainly indicative.

In order to calculate the Available Transfer Capacity (ATC), system operators require

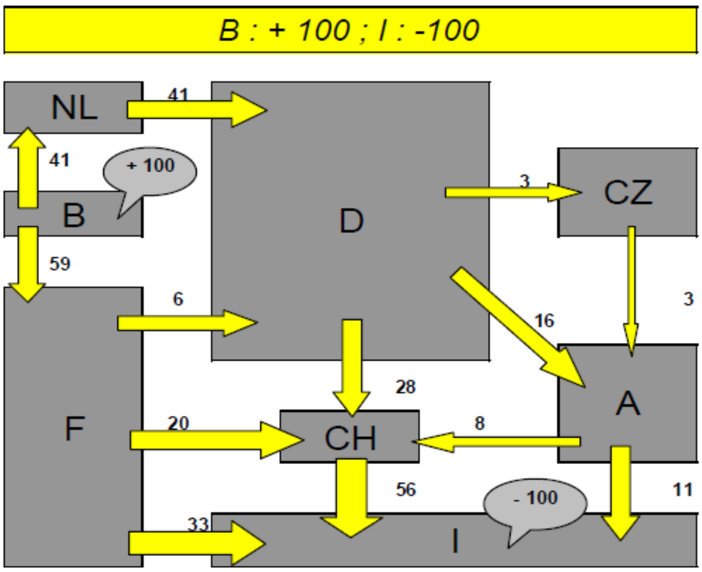

Figure 2.2 Example of European load flow for 100MW export. [19]

the information regarding generation schedules for the day-ahead market. By performing load flow calculations which correspond to the cross-border capacity already allocated through trade, flows between two regions are computed and are called Notified Transmission Flows (NTF) or Already Allocated Capacity (AAC). While the booking procedure continues, TSOs continuously receive information and update their simulation inputs to define any security risks. The results provide the remaining Available Transfer Capacity (ATC) which can be used between two regions, with respect to security [20]. ATC is part of NTC, and represents the remaining capacity available for commercial use, after each allocation phase. It is given by the following equation:

$$ATC = NTC - AAC$$

The values of Total Transfer Capacity (TTC), Transmission Reliability Margin (TRM) and Net Transfer Capacity (NTC) are computed for bidirectional interconnection flow and are not necessarily equal. Additionally, they are also time dependent. The two publishments annually correspond to seasonal capacities of two peak scenarios, one in winter and the other in summer. Another issue, is that in short time frame scenarios, for example hours ahead, previous allocations results are integrated into the base scenario. With varying peak times, forecasts do not fully represent real-time loads and as a result NTC values are mis-calculated [20]. The ATC model has been implemented by most power markets in EU region with at least one interconnection with other markets, where power flows not according to physical laws, but according to commercial paths from low price region to higher price ones. [21]

2.4.2. Flow-based market coupling

The Flow-based market coupling (FBMC) model is the new efficient and more advanced design of the market algorithm on calculating and allocating capacity in cross-border interconnections. This design focuses on a more approached depiction of the electrical grid, rather than the current method of Net Transfer Capacity (NTC). It offers the ability to prioritize the most economically efficient power flows while managing congestion in lines, contrast to the current state, where transmission system operators allocate capacity in advance [22]. The available capacity for commercial use as well as its allocation are calculated at the same time in an implicit manner. Thus, it allows usage of the interconnection in the direction where it is effectively used, maximizing the social welfare and exploiting scarce capacity efficiently. As stated above, NTC and ATC models do not take into account the impact that separated locations have on the whole network, when generation shifts in one of them. In flow-based analysis, physical laws and constrains are fully considered with more accurate grid representations. [23]

This method can be described as a combination of the zone approach from Available Transfer Capacity (ATC) method with the physical constraints of the transmission lines from the nodal market method. In the nodal model, nodes represent locations in the electrical grid, where generators inject power into the grid. Here, injection points are considered as a separate zone. Every node injects power in the grid and is called Net Exchange Position. By applying constrains in the clearing algorithm, the following apply for each node and each transmission line l connected to the node:

$$-P_l^{max} \leq P_l \leq P_l^{max}$$

$$P_l = \sum_{i=1}^{n} PTDF_{l,n}^{node} P_n$$

where $\boldsymbol{P_l}$ equals to power flow through the transmission line l, $\boldsymbol{P_l^{max}}$ the maximum power allowed on transmission line, $\boldsymbol{P_n}$ each power injected in the specific node from generating units and $\boldsymbol{PTDF_{l,i}}$ are the Power Transfer Distribution Factors. These parameters represent the linear relationship between injections in the grid and resulting flows through the lines. [24] In general, they represent the percentage of participation of an injection in a node, when the flow in a transmission line increases by 1MW. When modelling the FBMC model, the approach of zones is retained from ATC and the nodal market constraints are adopted in a simplified manner [25]. The combined method merges nodes into zones, where critical transmission lines are strictly taken into consideration in the market clearing process. In ATC model, the maximum power $\boldsymbol{P_l^{max}}$ is equal to the Available Transfer Capacity that TSOs calculate based on estimated data. The Net Exchange Position of each zone $\boldsymbol{NEX_z}$ now equals to the sum of all flows in transmission lines, connected to this zone. For each zone, the

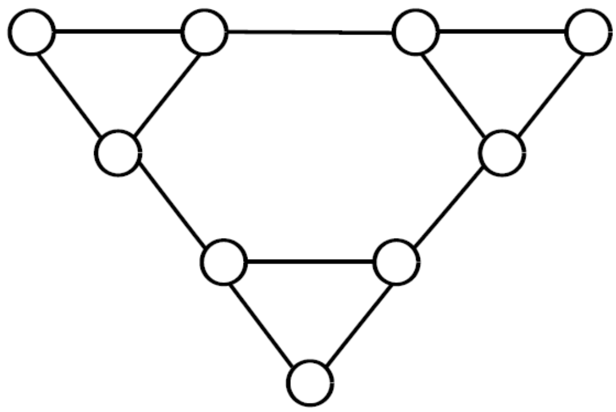

Figure 2.3 Example of a nodal network, with 9 nodes and 12 transmission lines. [24]

following equation applies:

$$NEX_z = \sum_{l=1}^{n} A_{l,z} P_l$$

where $\boldsymbol{A_{l,z}}$ is the network incidence index. Its value indicates whether the transmission flow of a line corresponds to an export ($\boldsymbol{A_{l,z} > 0}$), an import ($\boldsymbol{A_{l,z} < 0}$), or an unavailable connection ($\boldsymbol{A_{l,z} = 0}$). Figure 4 displays the aggregation of nodes into zones. The nodal market constraints are changed to the following form for each zone:

$$-RAM_l \leq P_l \leq RAM_l$$
$$P_l = \sum_{i=1}^{n} PTDF_{l,z}^{zone} NEX_z$$

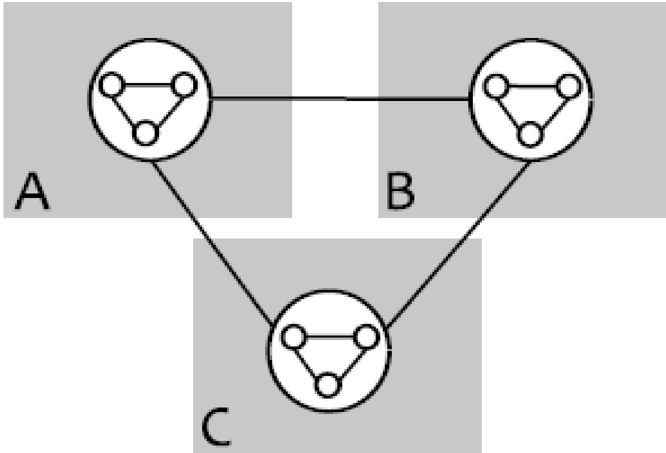

Figure 2.4 Aggregation of nodal model into zones. [24]

where $\boldsymbol{RAM_l}$ is the Remaining Available Margin of a critical line l, and $\boldsymbol{PTDF_{l,z}^{zone}}$ is the zonal Power Transfer Distribution Factor. The zonal PTDF provides the linear relationship between Net Exchange Positions and power flows in transmission lines. These two values are calculated by TSOs before the market clearing process and allow for increased traded capacity, since grid elements are better presented [24].

2.4.3. Model parameters

FBMC requires calculation of two important parameters: the Remaining Available Margin (RAM) and the zonal Power Distribution Factors [25]. The process begins two days before the day it refers to and completes the morning day-ahead, using a Base Case scenario as a starting point. The role of the TSOs is to determine which of the transmission lines are crucial and are most likely to be congested [23].

The Base Case Scenario refers to a forecasted state of the electricity system at the time of delivery and is crucial in calculating Generation Shift Keys (GKSs) and RAM. The first step in determining the Base Case is for system operators to determine one locally for their area of responsibility. For this purpose, another day with known market outcome is used as a reference. The reference day, usually a past day, has similar system characteristics with the day that has to be simulated. Such are the season of the year, day of the week, weather and temperature conditions. Then, the market scenario uses forecasted data for renewable generation, grid loads and unit scheduling. Finally, all TSOs merge their cases and coordinate Net Exchange Positions, to achieve a balanced system, but each with small methodology differences.

As stated above, Distribution factors refer to the network impact of production units in the meshed grid, when considered as a single grid. For the zonal model, these factors are calculated using the nodal Distribution Factors and another parameter called Generation Shift Keys (GSKs). GSKs display the participation of generating units of a node, to changes in power balance of a specific zone. [26] The $\boldsymbol{PTDF}$ and $\boldsymbol{GSK}$ values for a zone are calculated by the following equations:

$$PTDF_{l,z}^{zone} = \sum_{i=1}^{n} PTDF_{l,n}^{node} GSK_{n,z}$$

$$GSK_{n,z} = \frac{dP_n}{dNEX_z}$$

By default, approximation of nodal PTDF values to zonal values results in inaccuracies due to grouping of nodes to zones. Exact information on injections in nodes is neglected. Additionally, GSK values are computed based on predictions of the market clearing outcome, which is subject to the Base Case taken into account. Therefore, errors are present in every allocation scenario and as a result, the available capacity is reduced by a safety margin for security reasons. An issue while calculating GSK values is that they only refer to generating units that have flexibility in managing output and are market-driven. Such units are hydrocarbon-fired power plants (coal, gas, oil) and conventional hydro units. Renewables have variable production and their forecasted output is prone to deviation [27]. In Central-Western European region, each TSO calculates values for his own area, and are all combined together in a final table of values.

The second important parameter is the Remaining Available Margin (RAM). It represents the capacity of the line that can be used by the day-ahead market. For each critical line, the RAM is calculated for high-risk conditions, which are outages in critical locations and the following equation applies:

$$RAM_l = P_l^{max} - P_l^{ref} - FAV_l - FRM_l$$

where:
$\boldsymbol{P_l^{max}}$ is the maximum power cables in critical lines can transfer
$\boldsymbol{P_l^{ref}}$ is the flow caused by transactions outside the day-ahead power exchange
$\boldsymbol{FAV_l}$ is the Final Adjustment Value that TSOs account as a safety margin for remedial actions in unexpected events
$\boldsymbol{FRM_l}$ is the Flow Reliability Margin that compensates for approximations applied when simplifying the grid to zonal topology.

Once both parameters are computed, the algorithm runs a verification process to check that the market result does not endanger network security. At this stage, system operators can introduce extra constraints at will to ensure stability. The method can also adapt anti-intuitive flow measures to avoid flows from high price areas to low price areas. The advanced method is also known as Intuitive Flow Based Market Coupling. [25]

If RAMs in all critical branches can support all transactions for electricity exchanges between all zones, then prices will be the same in all zones. On the contrary, an active constraint in one of the lines means that RAM is fully exhausted in this line and congestion is present. In this case, all prices in zones are affected in relation to the PTDF values. Active constraints in a line impose shadow prices, that represent social welfare increases per unit of more available capacity in the market. Shadow price is calculated by the following equation:

$$\frac{Pr_z - Pr_y}{PTDF_y - PTDF_z} = S.P. \geq 0$$

Zones $\boldsymbol{y}$ and $\boldsymbol{z}$ are part of the same region and $\boldsymbol{Pr}$ their corresponding prices. Since a line is now congested, that means that dispatches have to be adjusted to avoid its overloading. Therefore, prices for all zones are subject to changes. In general, for every critical line applies that lower PTDF values amount to higher price in that zone. Overall, for each zone the following applies:

$$Pr_z - Pr_y = \sum_{l \in CL} (PTDF_y - PTDF_z)\mu_l$$

Where μ_l is the shadow price of each critical lines in the set of CL that contains all critical lines. The above equation states that price difference between two zones is equal to the sum of PTDF differences multiplied by the shadow price of the critical line, for all lines. PTDF values only have a meaning, when calculating their differences between two zones, which attribute to the incremental flow of a 1MW transaction between the two zones. [28]

2.4.4. ATC-NTC and FBMC model comparison

Both models have been used in the electricity markets of the European region, with FBMC being introduced in the last years. Market algorithm in ATC uses an input only data regarding the regions that are under study. To determine the maximum capacity that can be used in trading for each interconnector, the algorithm relies on market forecasts based on historical data for the two regions that share borders. Congestions in transmission lines are solved border by border, and it is up to TSOs to manage the real physical flows, including transit flows in order to achieve system balance. This means that certain key locations, where congestions are traditionally observed, receive prioritized capacity allocation. Even though such management might seem easier in its application, it offers reduced trading opportunities. Available Capacity is by definition miscalculated, as the laws of physics and grid characteristics are ignored. Still, it offers acceptable results in early stages of market coupling between regions who wish to establish cross border trading. [22]

FBMC does things differently, though. A more accurate description of the electrical grid is adopted. Grid topology as well as generating units information are used by the algorithm to calculate physical flows in all critical transmission lines, with the aim of effectively allocating available capacity for usage by market traders. The result is higher transmission capacity available than ATC model, that also respect natural flow of power. However, additional effectiveness comes at a cost. This method requires substantially more analyses to be performed and data to be used, in order to forecast the market prices at the reference day of clearing. In general, it is observed that FBMC finds more optimal solutions than ATC, but the same cannot be said for the level of system security. [27]

3. Market Coupling Model

3.1. Defining the model

In this chapter, a market coupling model will be described. This model was designed and simulated using the software ***MATlab*** developed ***by MathWorks.*** To perform the coupling of power markets between two regions, a system must be defined. It includes two regions, A and B, with an established transmission line that connects them.

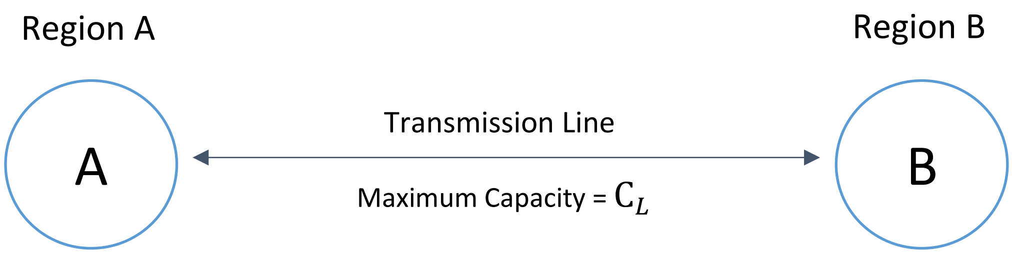

Figure 3.1 Two regions, A and B, with a transmission line between them.

As stated in chapter 2.4.2, a transmission line can only transport as much power as its physical and electrical characteristics allow. Therefore, the power that each region can deliver through trade cannot exceed $\mathbf{C_L}$, which is the maximum capacity allowed in the transmission line. To satisfy this constrain, the following equations are applied for regions A and B:

$$Q_{tr\ A\to B} \leq C_L \tag{3.1}$$

$$Q_{tr\ B\to A} \leq C_L \tag{3.2}$$

where $\boldsymbol{Q_{tr\ A\to B}}$, $\boldsymbol{Q_{tr\ B\to A}}$ is the power that is traded and delivered from A to B, and B to A respectively.

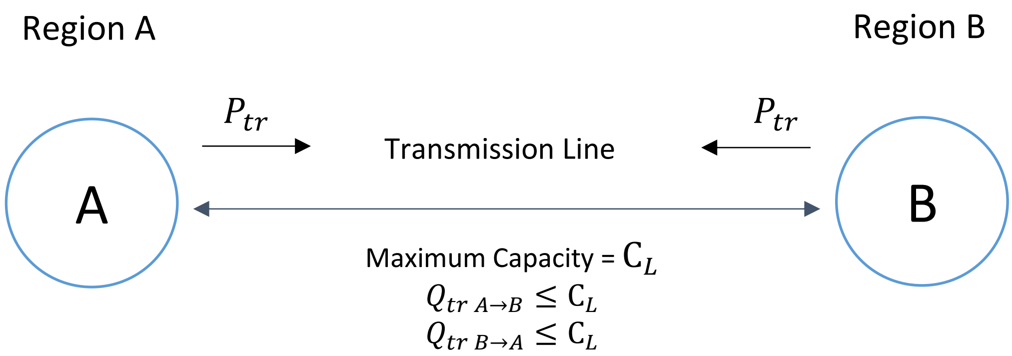

Figure 3.2 Two interconnected regions, A and B, exchanging energy between them.

Since each region operates each own power market, it should have a separate day-ahead and intra-day market, where generators and retailers submit their bids for offer and demand in energy. Each bid consists of two values, the amount of energy willing to buy or sell and the price per unit. $\boldsymbol{Qd_{A,i}}$, $\boldsymbol{Pd_{A,i}}$ represents a demand bid in Region A, where $\boldsymbol{Qd_{A,i}}$ is the submitted quantity and $\boldsymbol{Pd_{A,i}}$ the price, whereas $\boldsymbol{Qo_{A,i}}$, $\boldsymbol{Po_{A,i}}$ represents an offer bid. Similarly, $\boldsymbol{Qd_{B,i}}$, $\boldsymbol{Pd_{B,i}}$ and $\boldsymbol{Qo_{B,i}}$, $\boldsymbol{Po_{B,i}}$ are a demand and an offer bid in Region B.

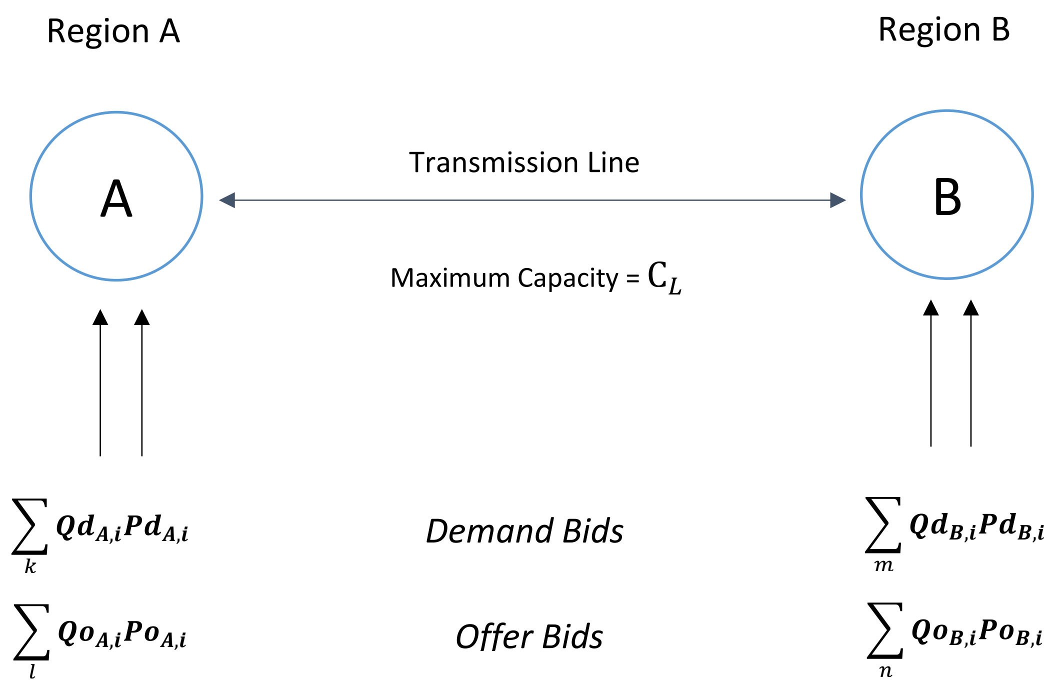

Figure 3.3 Two interconnected regions, A and B. Each region has a set of demand and offer bids.

Once the bids are submitted, the next step is to match demand and supply. Highest priced demand quantities are matched with lowest priced supply quantities. The process completes when the price of demand equals the price of supply, or when accepted generations have covered the region load forecasted for the specific time sequence. Load forecast is usually performed by the Independent System Operator. For this simulation, the forecasted system load is not taken into account when performing the market clearing. Therefore, the clearing prices are solely driven by the supply and demand bids.

After the market clearing happens, both regions have a price value that corresponds to the price of each unit of MW. Both sellers and buyers will satisfy their bids with a fixed price. In figure 3.4 $\boldsymbol{Pr_A}$ refers to the market price of region A and $\boldsymbol{Pr_B}$ to the market price of region B. In case a difference in the two prices exists, then an opportunity for trade is given. Assuming that $\boldsymbol{Pr_A} > \boldsymbol{Pr_B}$, region A is willing to accept volumes of energy from region B, because the price per unit is cheaper. At the same time, region B is willing to send volumes of energy to region A, because each unit of energy costs more. If the interconnection between the two regions is active, then region B can use this connection to transfer energy to A, provided that the constraints mentioned above are satisfied.

In such a scenario, the region that has the smallest price is the one to sell energy to the region with the highest price, with the incentive of profit.

- Since $\boldsymbol{Pr_A > Pr_B}$, region B must now compensate for the volume of energy it is willing to trade to region A. This translates to an increase in demanded volumes at region B, equal to the traded volume, and at the price of region A, namely $\boldsymbol{Pr_A}$. As a result, a new demand bid is added, $\boldsymbol{(Q_{tr\ B\rightarrow A}, Pr_A)}$.
- On the other hand, region A must now compensate for the volume of energy it is willing to buy from region B. The energy received will be added as generation in the grid, at the price of region B, namely $\boldsymbol{Pr_B}$. Thus, a new offer bid is added, $\boldsymbol{(Q_{tr\ B\rightarrow A}, Pr_B)}$.
- Once new bids have been added to the market pools, the market clearing process must take place again for both regions.

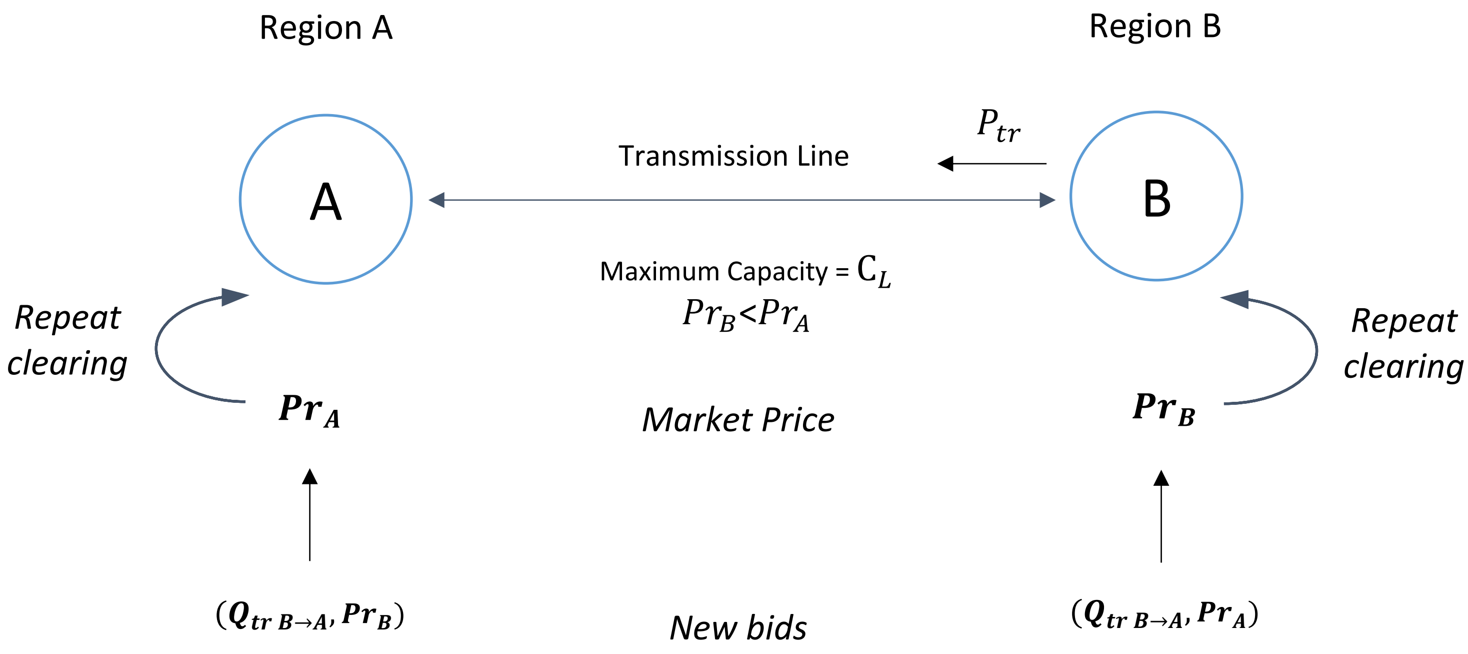

Figure 3.4 Two interconnected regions, A and B. Region A has a lower market price.

It is made clear that this process will result in change of prices for both regions. Since the more expensive region receives energy at a lower price, the new market clearing price should be lower than the previous one. Similarly, the cheaper region will sell at a higher price and as a result should cause its domestic price to raise. The process will keep repeating, until one of the following conditions is satisfied:

$$\boldsymbol{Pr_B = Pr_A} \qquad (3.3)$$

or

$$\boldsymbol{P_{tr} > Generation\ Surplus\ of\ region\ B} \qquad (3.4)$$

Condition (3.4) implies that the region with the lower price, in this example region B, cannot provide volumes of energy through trade, which exceed the available non-accepted supply bids. Briefly, region B cannot deliver to region A more energy than the one it can produce.

Condition (3.3) implies that once both regions reach the same market price, then there is no further incentive to trade, since no profit will be made.

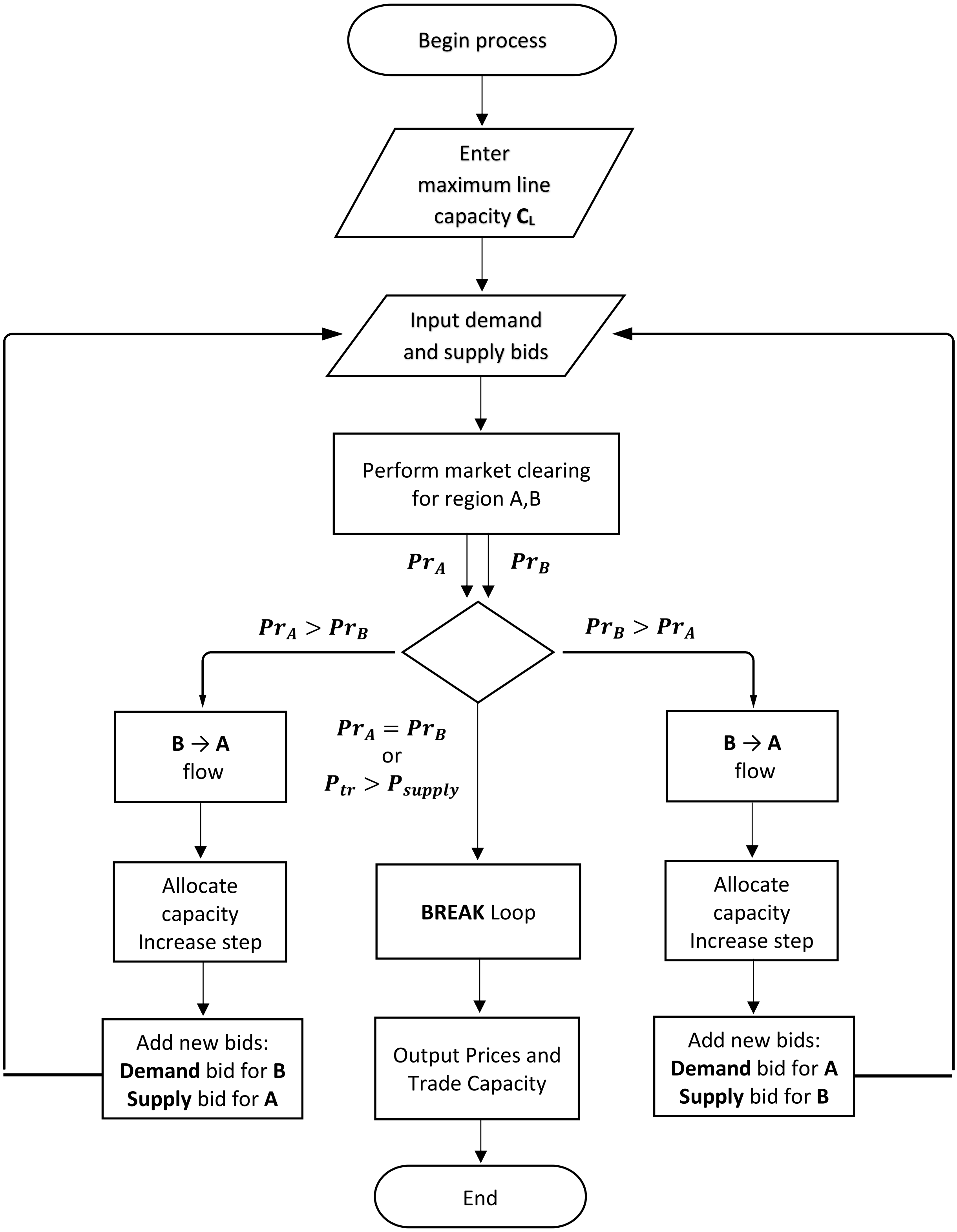

Figure 3.5 Simulation flowchart.

3.2 Simulation flowchart

For the simulation of market coupling of two regions, a set of demand and supply bids will be inserted as input for each region. Each set contains multiple bids of paired values (quantity in MW – price per MW), with overall 24 sets. Each set represents a 1-hour segment of the day. The data used are the published energy offers from Hellenic System Administrator (ADMIE) for two days, 17th February,2021 and 18th June, 2021. [29]

In figure 3.5, a flowchart representation of the simulation program is shown. At the beginning of the process, the user is required to input the value of maximum capacity of the transmission line. This value will be used to evaluate equations (3.1) and (3.2). The next step is to input the data sets for region A and B. For each region, two files containing the sets of bids are assigned, one for demand bids and the other for supply bids. The program reads those files and inputs the corresponding data. Once the input is completed, the market equilibrium for each region is calculated.

Depending on the correlation of the two region prices, the process decides on the direction of traded flow. If the value of the maximum transmission capacity is set to zero, then the interconnector is not active and the process will only clear the markets based on the initial supply and demand data.

When any statement of (3.3) or (3.4) becomes true, the loop breaks and the program outputs the n-1 values of prices and calculated capacity for trade, as the accepted solution, since n-solution violates the conditions. At this point, it must be noted that once the direction of trade is decided, due to price difference, it cannot be changed. If, for example, region A has a lower price than region B, region A will always sell energy to region B until the prices completely diverge.

3.3 Simulation – 24h Market clearings

In figures 3.6-3.29 below, the market clearings prices are displayed for regions A and B, in 1-hour segments for a single day. For each region, the market price (*Y-axis*) and quantity in MW (*X-axis*) is shown. Clearing the two market separately, corresponds to the scenario of non-active interconnection between them.

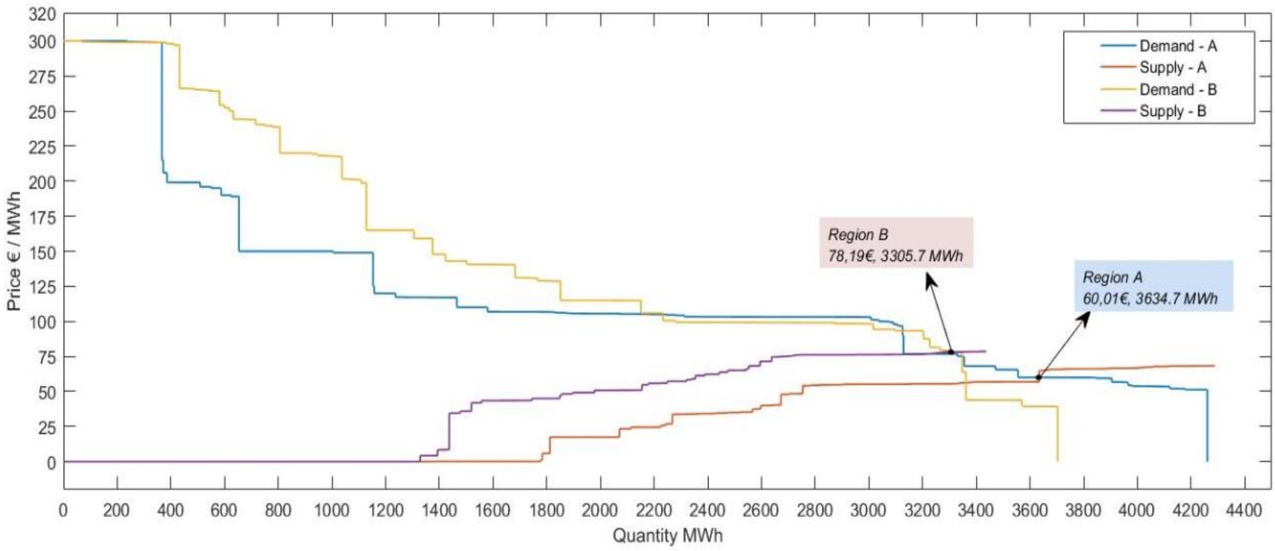

Figure 3.6 *Region* A and B market clearing, Hour 00:00.

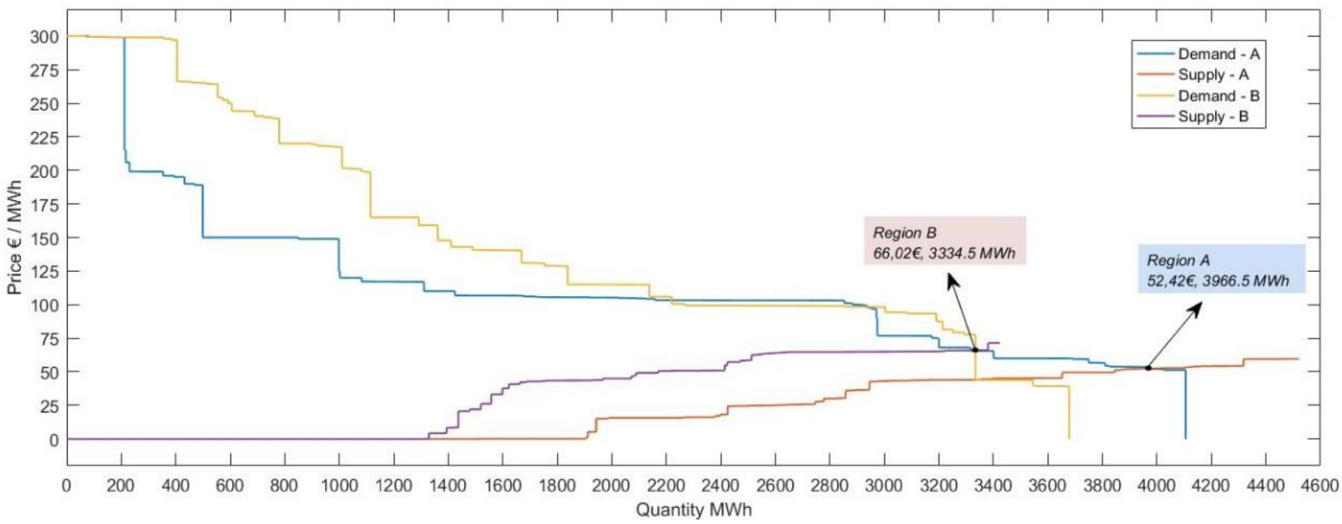

Figure 3.7 Region A and B market clearing, Hour 1:00.

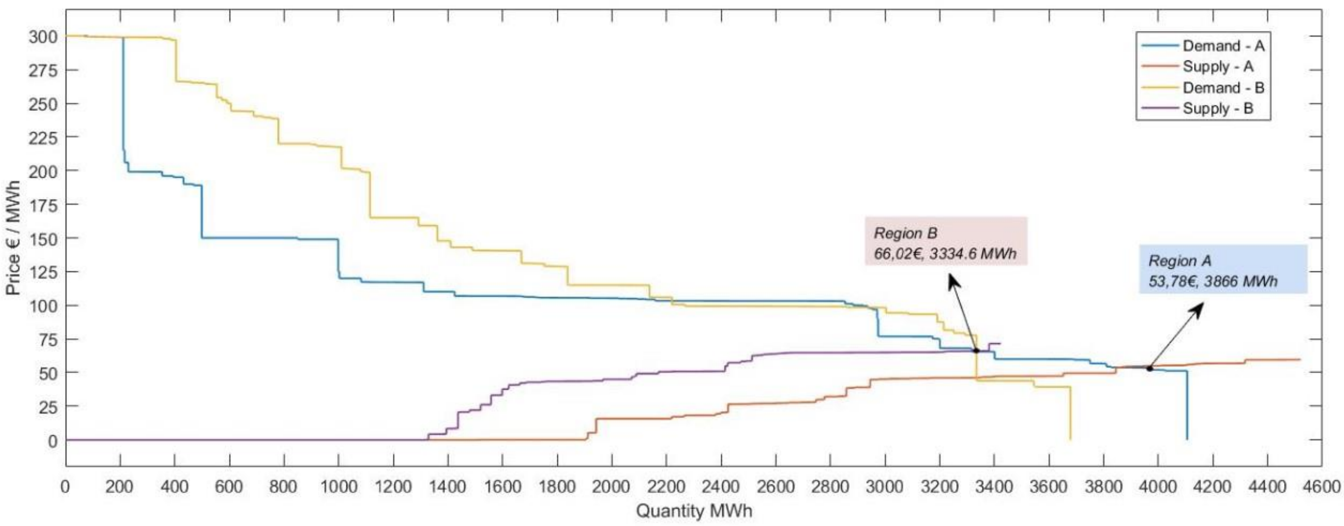

Figure 3.8 Region A and B market clearing, Hour 2:00.

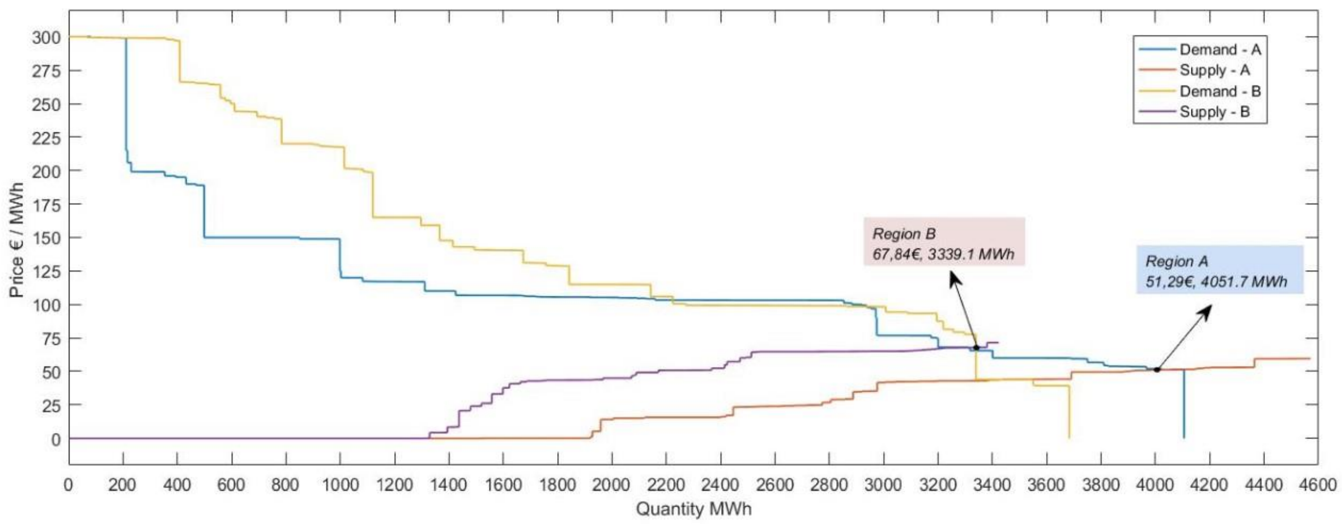

Figure 3.9 Region A and B market clearing, Hour 3:00.

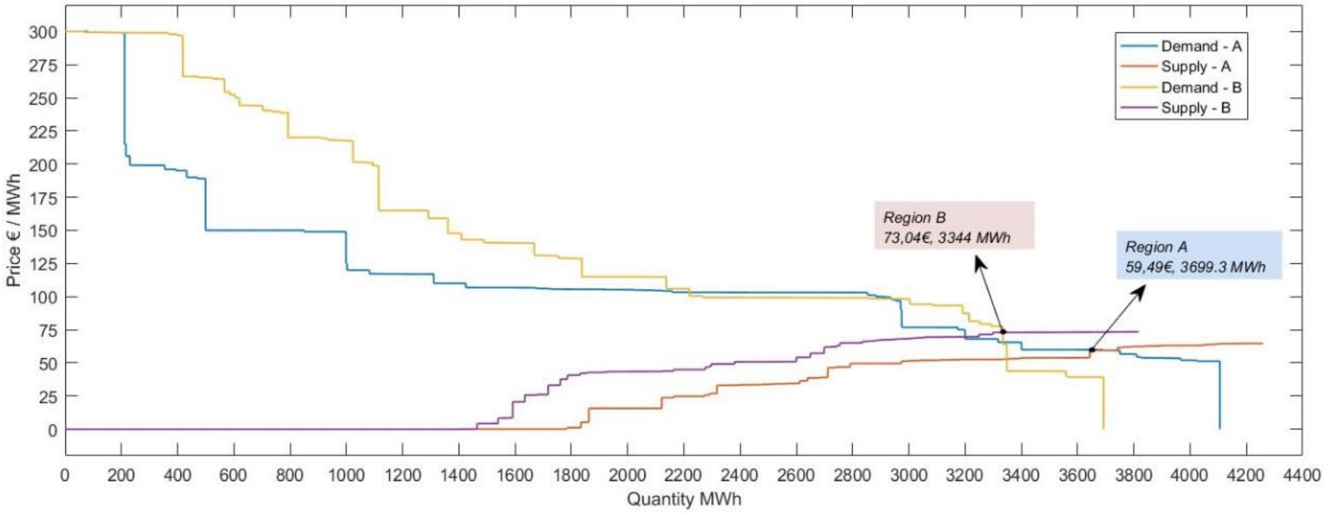

Figure 3.10 Region A and B market clearing, Hour 4:00.

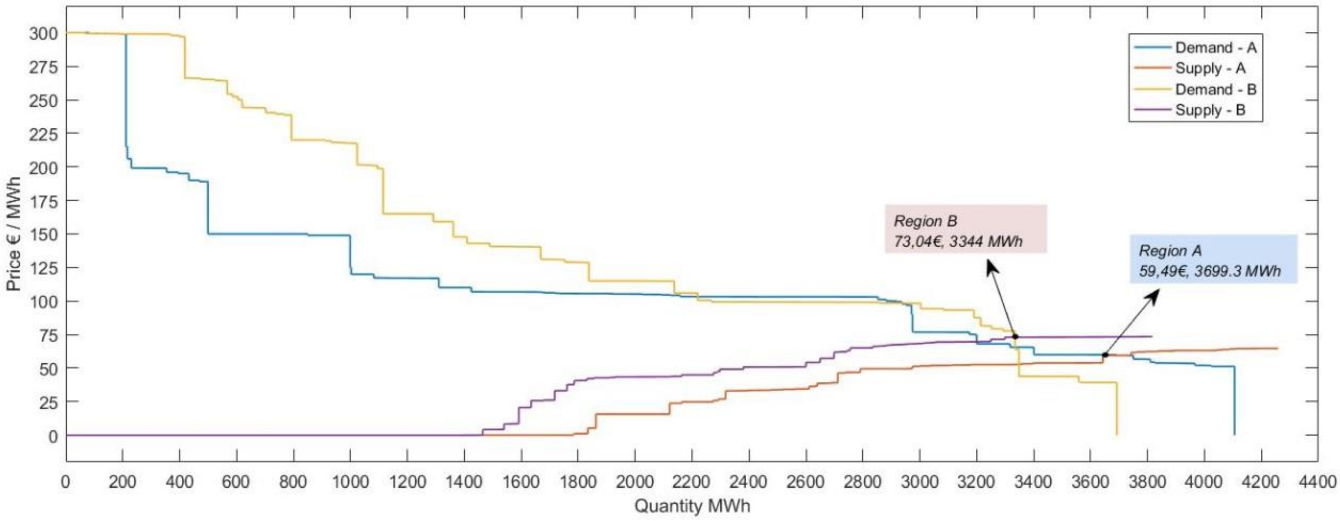

Figure 3.11 Region A and B market clearing, Hour 5:00.

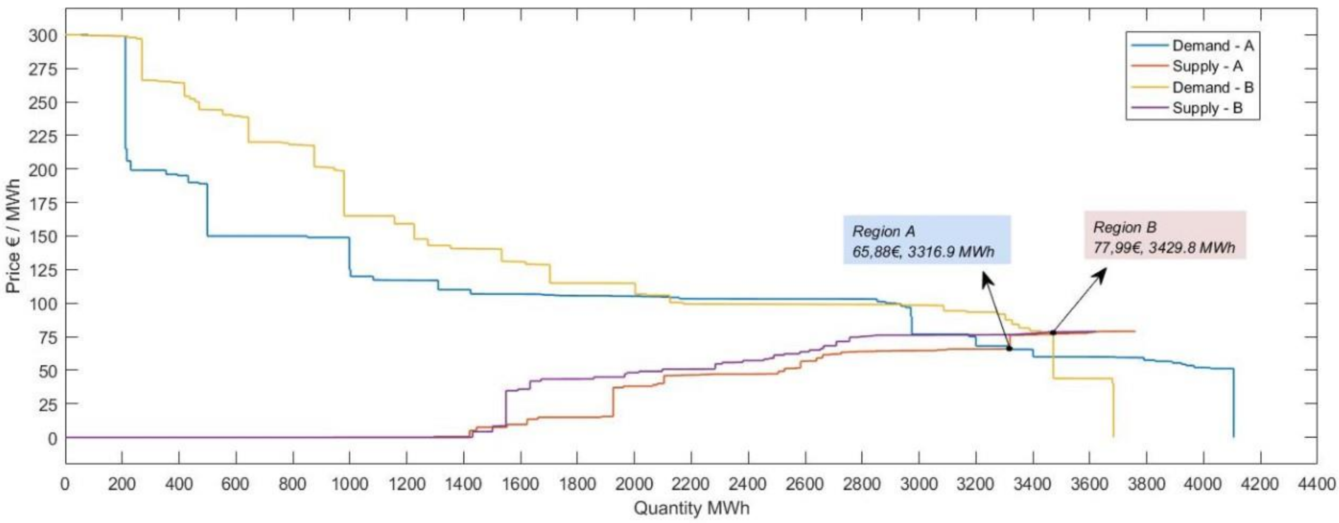

Figure 3.12 Region A and B market clearing, Hour 6:00.

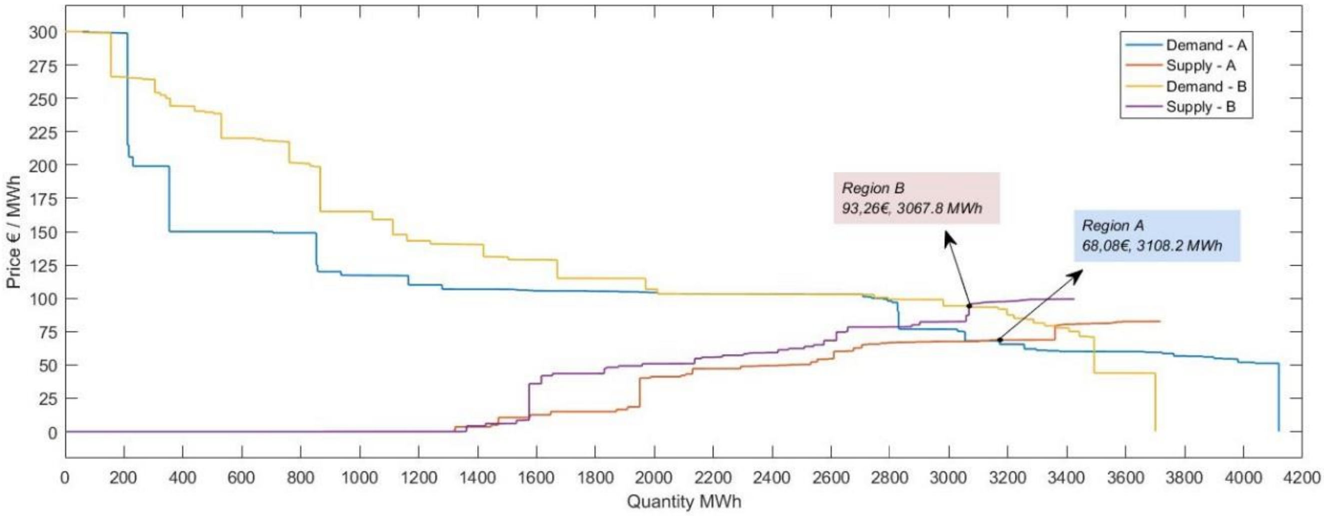

Figure 3.13 Region A and B market clearing, Hour 7:00.

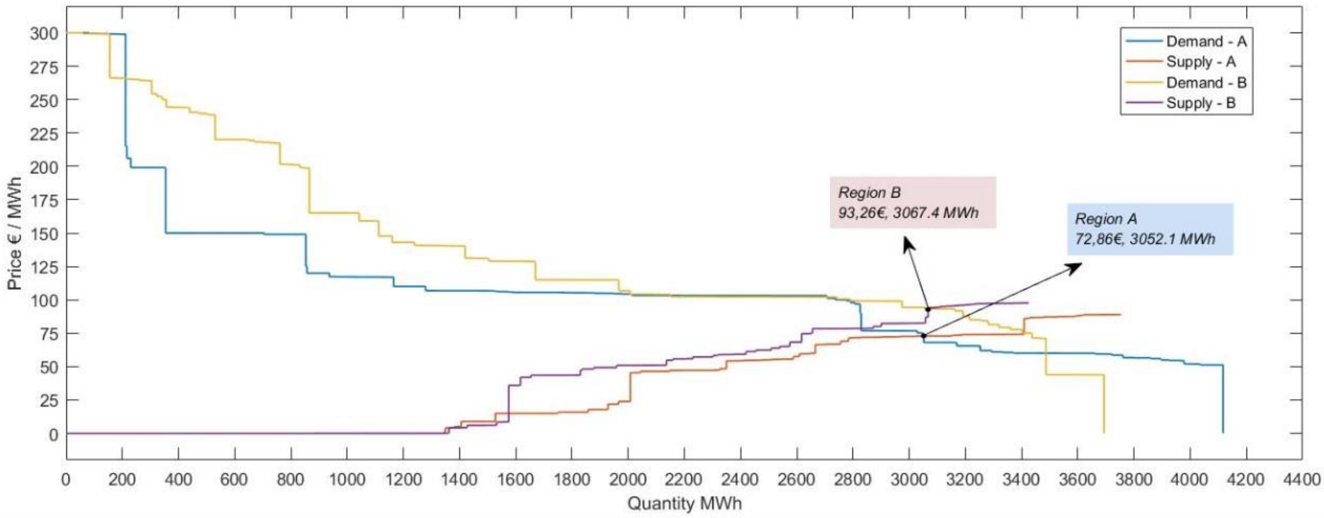

Figure 3.14 Region A and B market clearing, Hour 8:00.

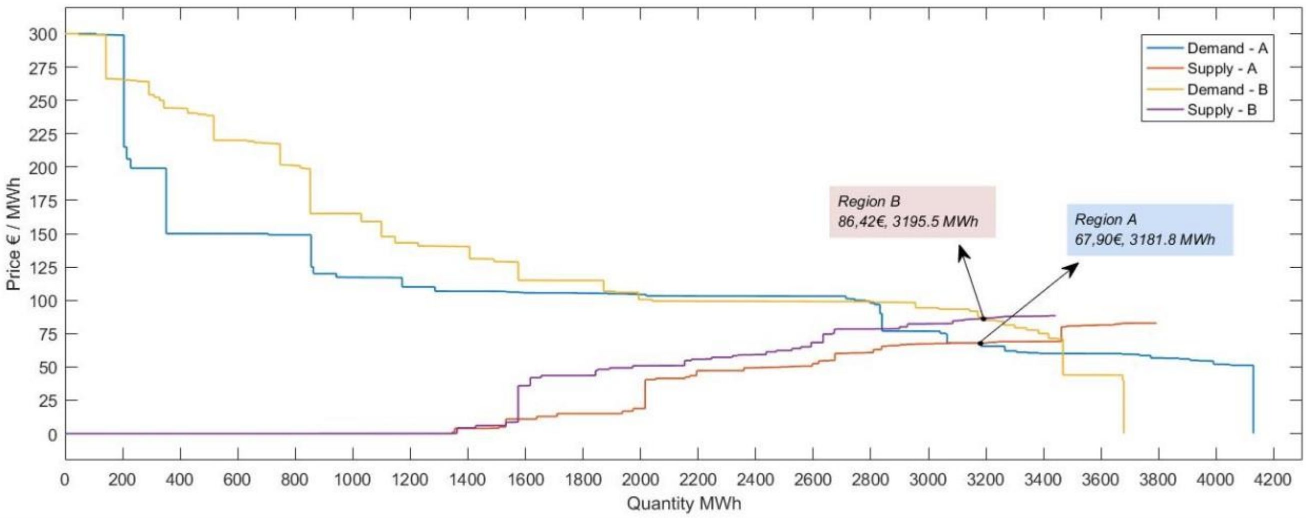

Figure 3.15 Region A and B market clearing, Hour 9:00.

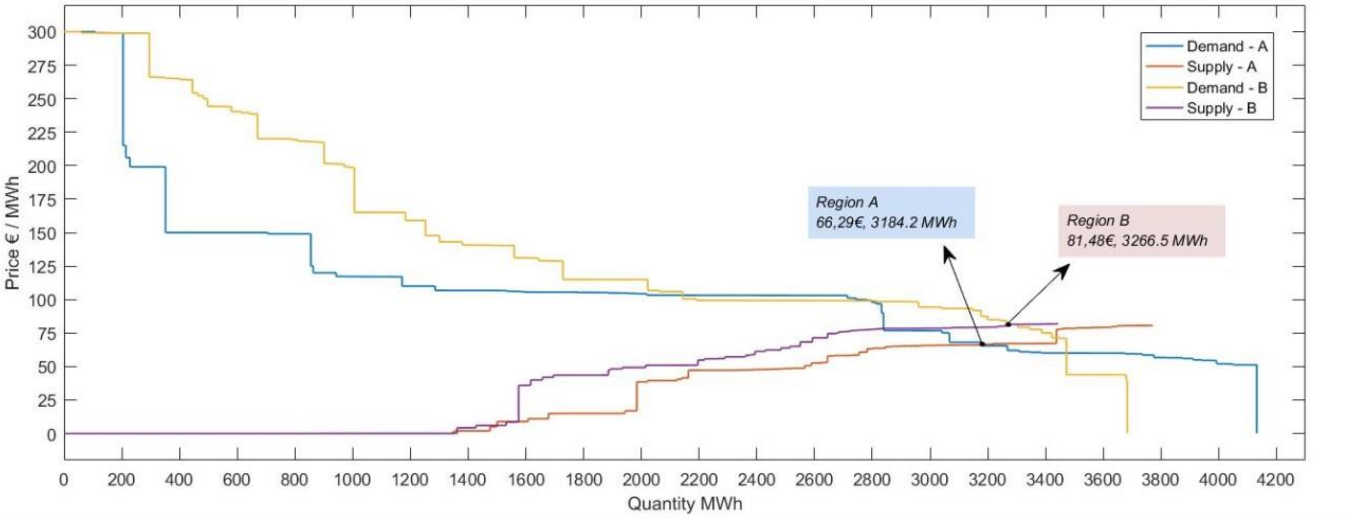

Figure 3.16 Region A and B market clearing, Hour 10:00.

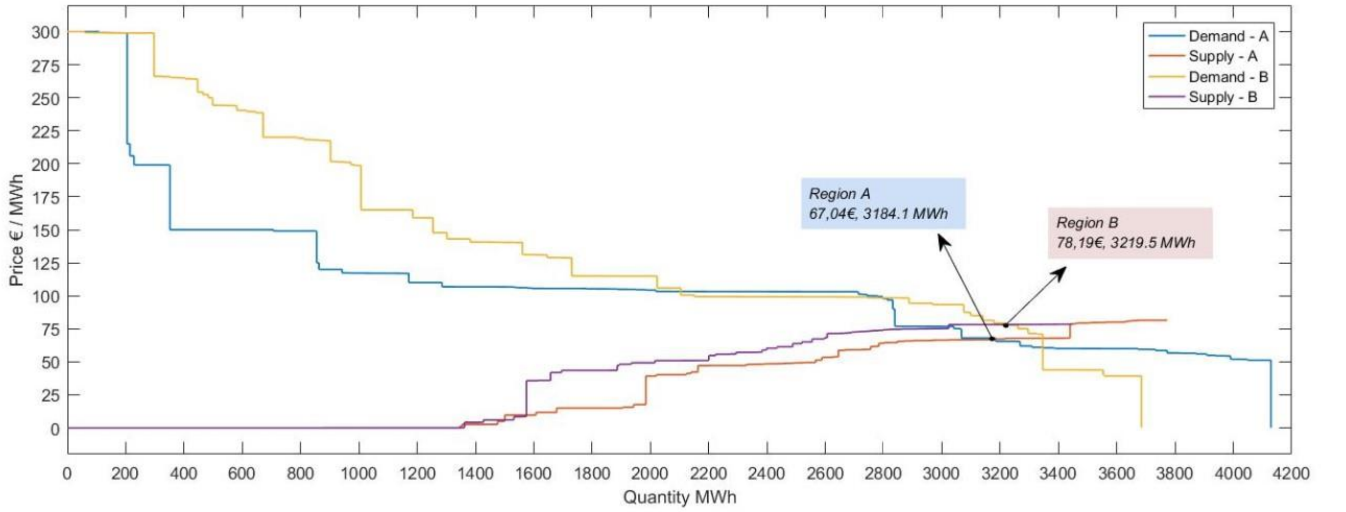

Figure 3.17 Region A and B market clearing, Hour 11:00.

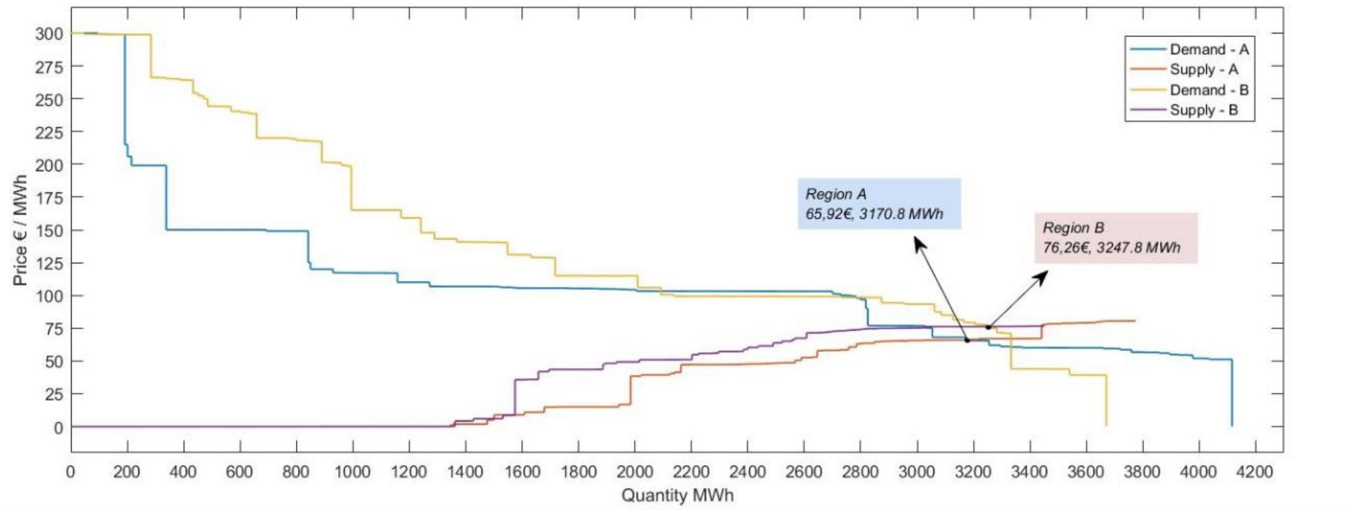

Figure 3.18 Region A and B market clearing, Hour 12:00.

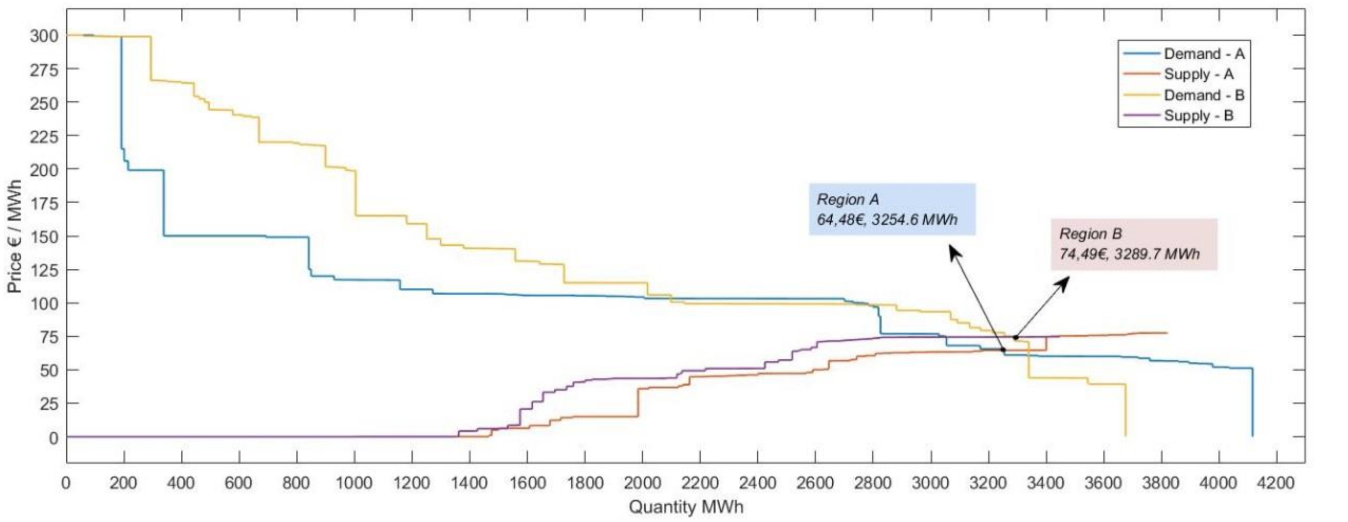

Figure 3.19 Region A and B market clearing, Hour 13:00.

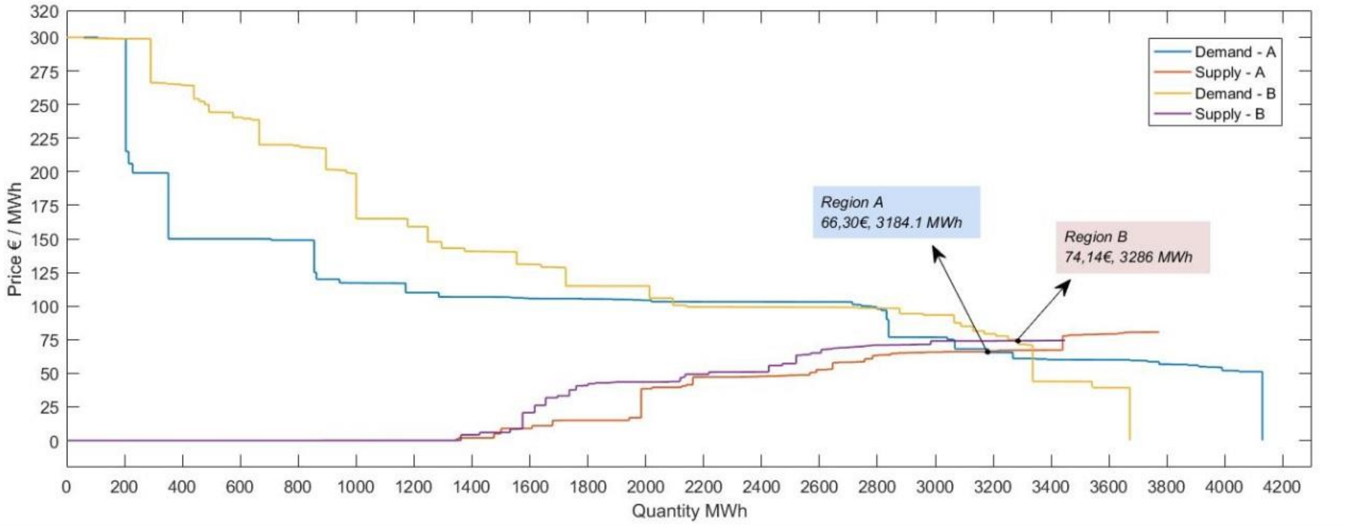

Figure 3.20 Region A and B market clearing, Hour 14:00.

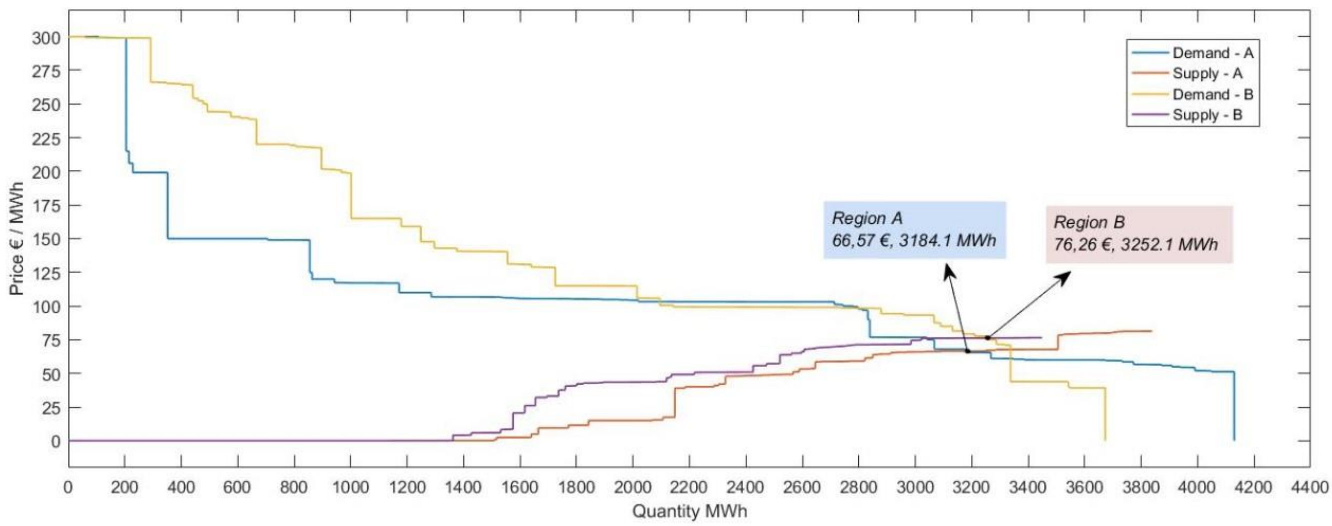

Figure 3.21 Region A and B market clearing, Hour 15:00.

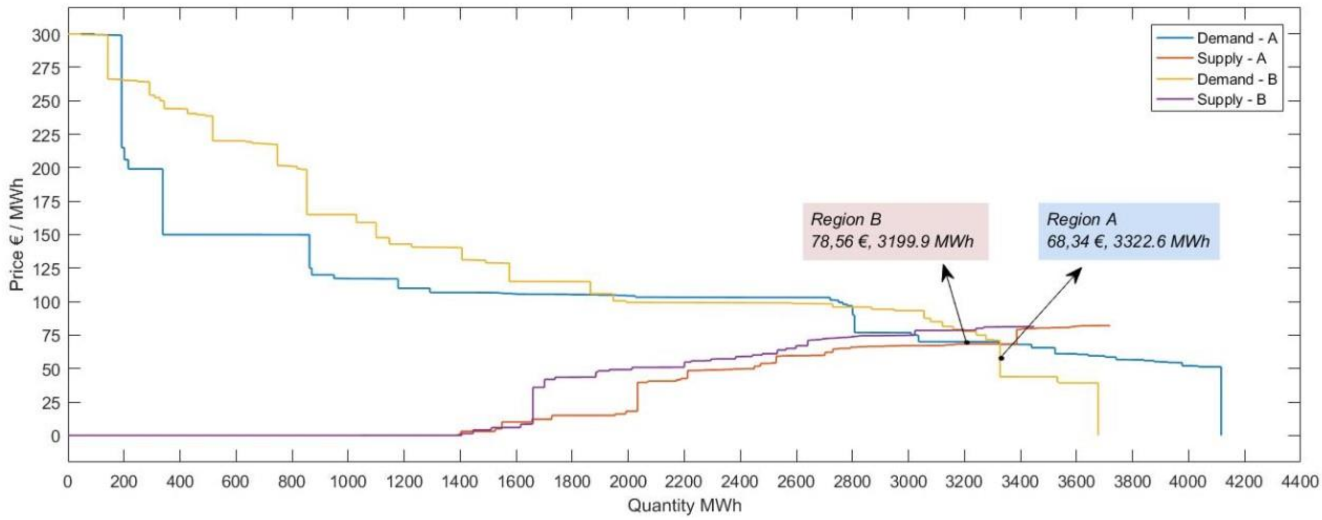

Figure 3.22 Region A and B market clearing, Hour 16:00.

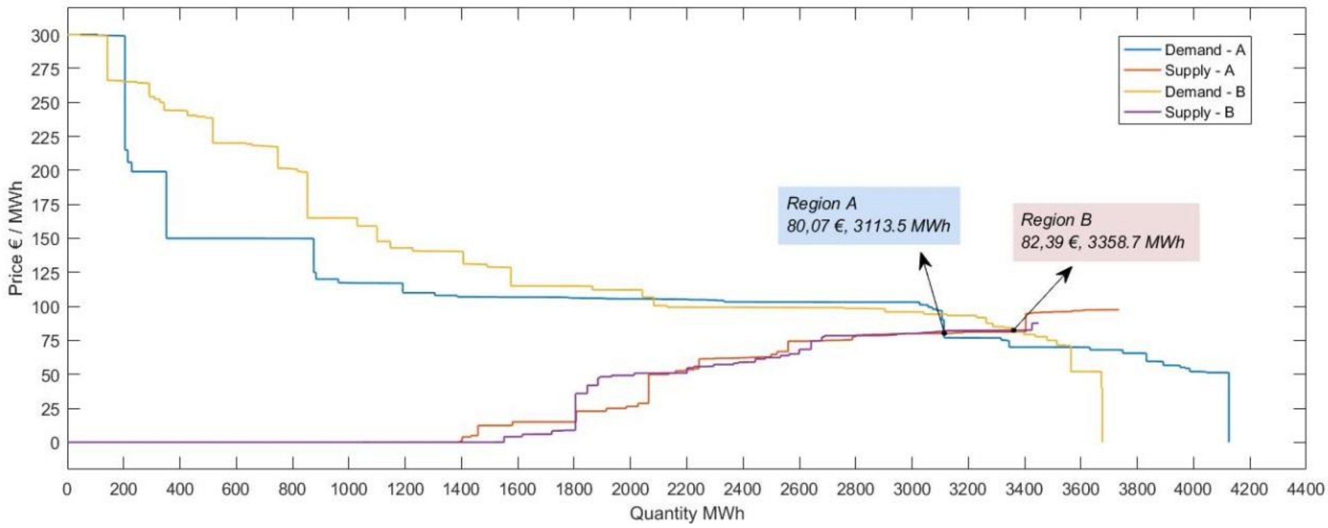

Figure 3.23 Region A and B market clearing, Hour 17:00.

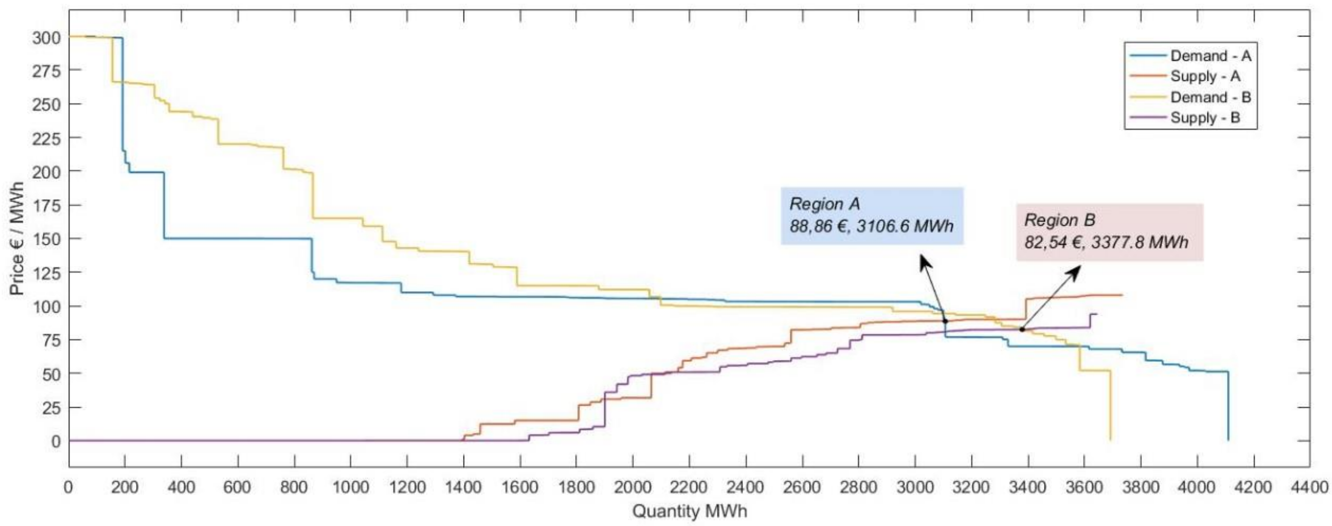

Figure 3.24 Region A and B market clearing, Hour 18:00.

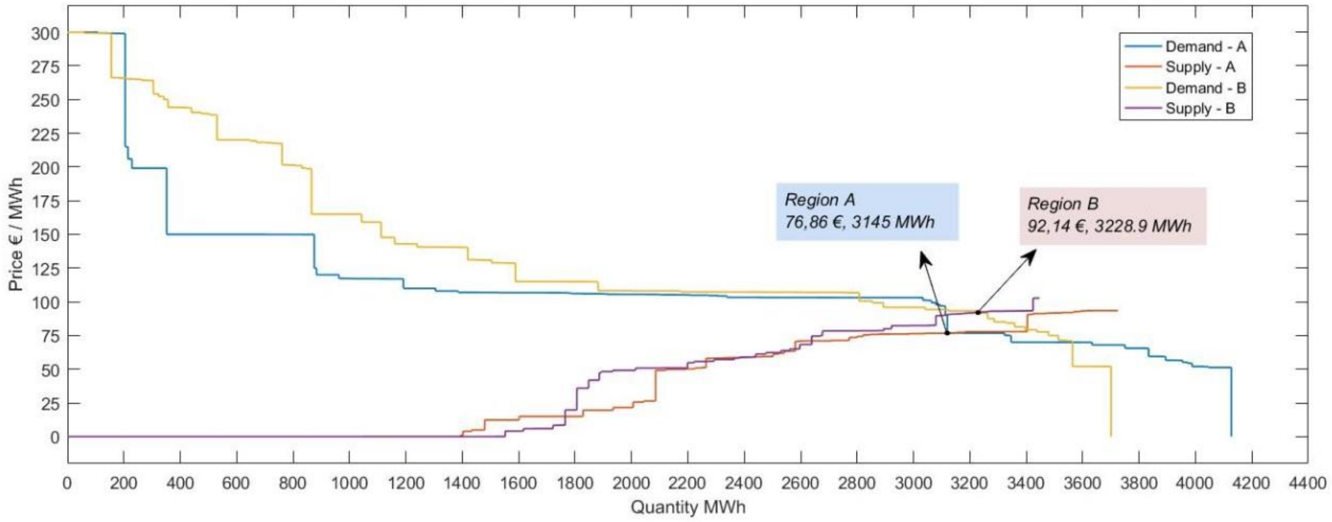

Figure 3.25 Region A and B market clearing, Hour 19:00.

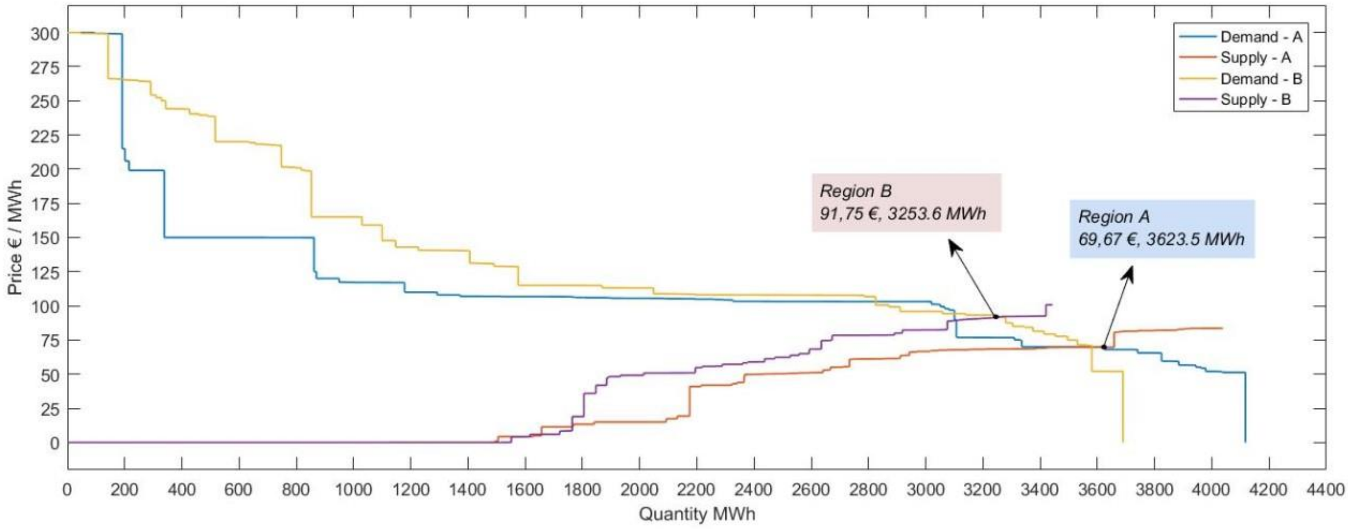

Figure 3.26 Region A and B market clearing, Hour 20:00.

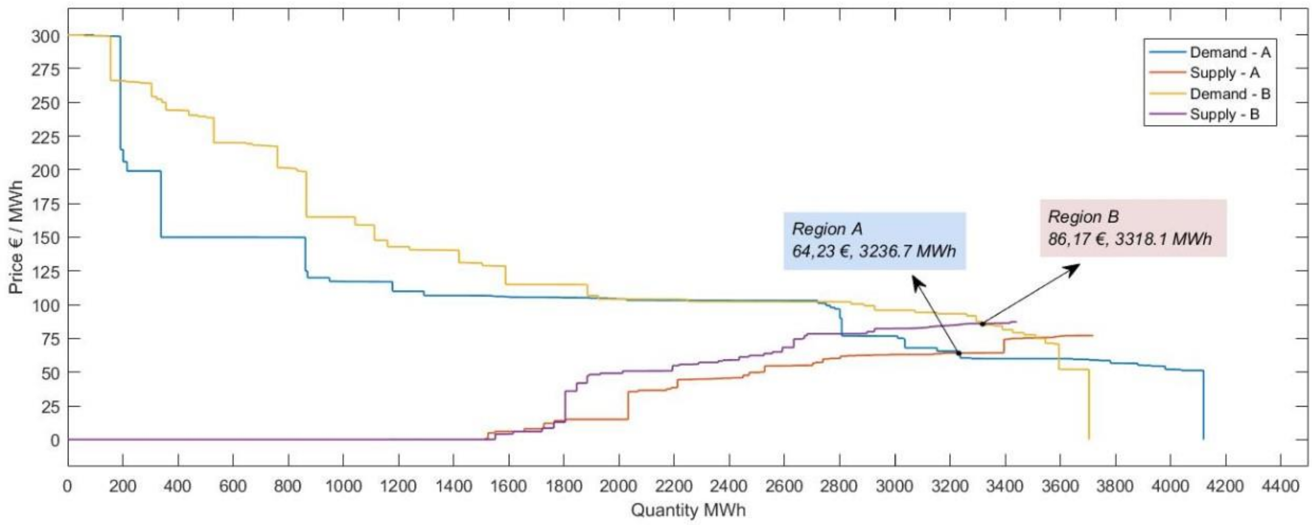

Figure 3.27 Region A and B market clearing, Hour 21:00.

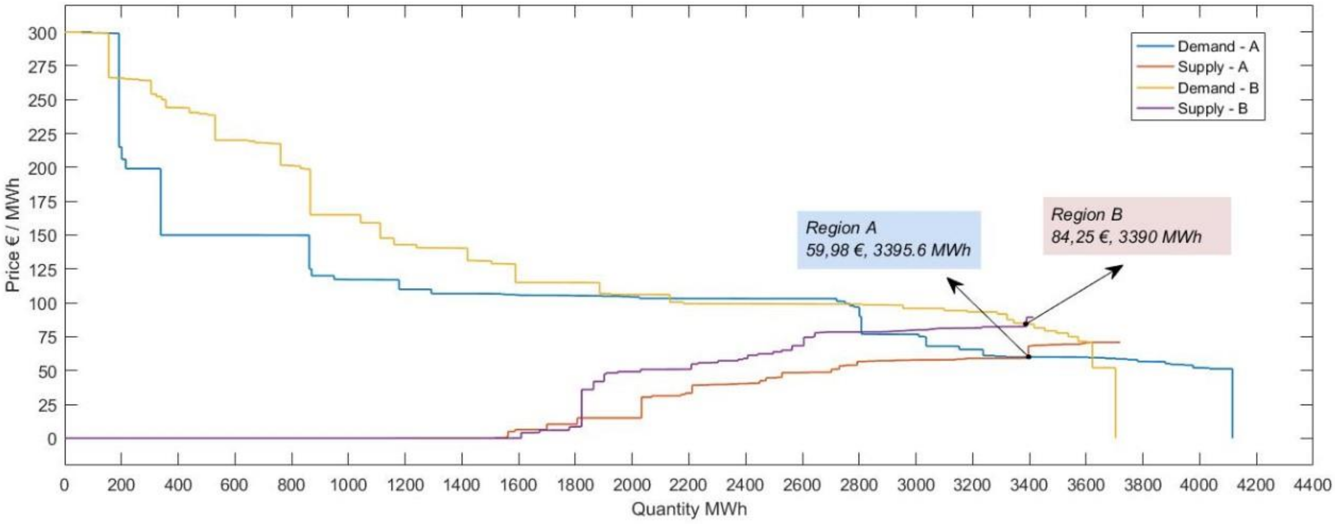

Figure 3.28 Region A and B market clearing, Hour 22:00.

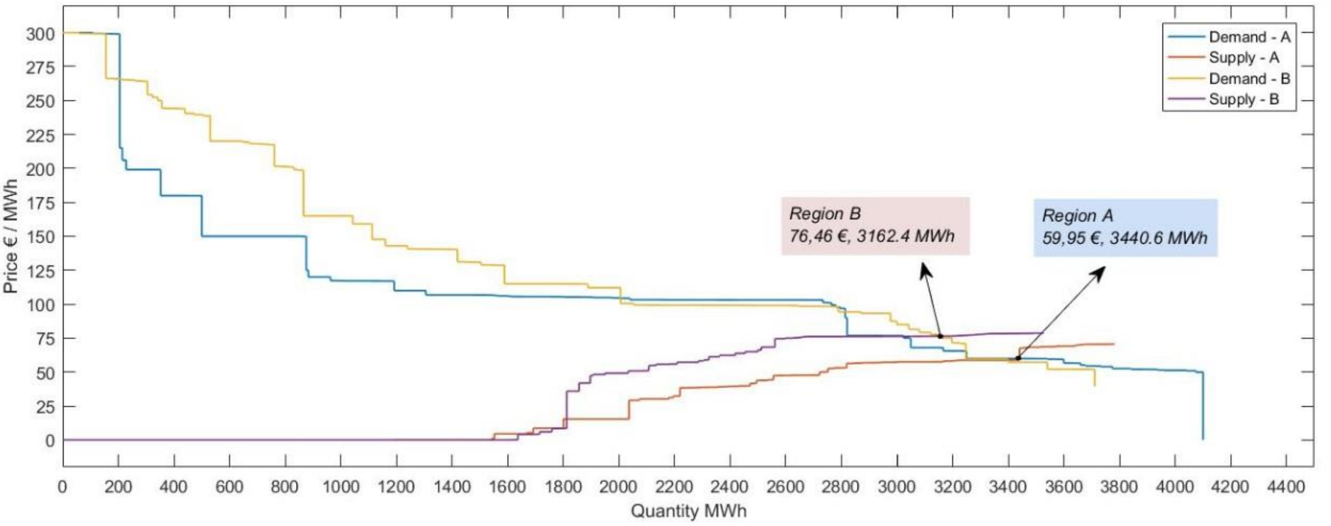

Figure 3.29 Region A and B market clearing, Hour 23:00.

In table 3.1, all the data for each region is shown collectively. The table displays prices and quantity of the market clearing process for each hour of a selected day.

In figure 3.30, the price profiling of the two markets is shown. By inspecting the graph trends, it can be noticed that the price per MWh is increasing rapidly when approaching hour segments with high demand in electricity, like morning hours (7:00 to 9:00) and evening hours (17:00 to 22:00), while on the other hand prices are lower during noon and night times. This can be attributed to the intensity of human activity during those hours. In red columns, the differences in market clearing prices are displayed. The profile of price differences is strongly related with the data in the following chapters, where the coupling results are shown.

Hours	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00
Region A												
Price PA (€/MWh)	*60.01*	*52.42*	*53.78*	*51.29*	*59.49*	*59.49*	*65.88*	*68.08*	*72.86*	*67.90*	*66.29*	*67.04*
MWh quantity	*3634.7*	*3966.5*	*3866*	*4051.7*	*3699.3*	*3699.3*	*3316.9*	*3108.2*	*3052.1*	*3181.8*	*3184.2*	*3184.1*
Region B												
Price PB (€/MWh)	*78.19*	*66.02*	*66.02*	*67.84*	*73.04*	*73.04*	*77.99*	*93.26*	*93.26*	*86.42*	*81.48*	*78.19*
MWh quantity	*3305.7*	*3334.5*	*3334.6*	*3339.1*	*3344*	*3344*	*3429.8*	*3067.8*	*3067.8*	*3195.5*	*3266.5*	*3219.5*

Hours	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Region A												
Price PA (€/MWh)	*65.92*	*64.48*	*66.30*	*66.57*	*68.34*	*80.07*	*88.86*	*78.86*	*69.67*	*64.23*	*59.98*	*59.95*
MWh quantity	*3170.8*	*3254.6*	*3184.1*	*3184.1*	*3322.6*	*3113.5*	*3106.6*	*3145*	*3623.5*	*3236.7*	*3395.6*	*3440.6*
Region B												
Price PB (€/MWh)	*76.26*	*74.49*	*74.14*	*76.26*	*78.56*	*82.39*	*82.54*	*92.14*	*91.75*	*86.17*	*84.25*	*76.46*
MWh quantity	*3247.8*	*3289.7*	*3286*	*3252.1*	*3199.9*	*3358.7*	*3377.8*	*3228.9*	*3253.6*	*3318.1*	*3390*	*3162.4*

Table 3.1 *Hourly prices and MWh quantities for Region A and B.*

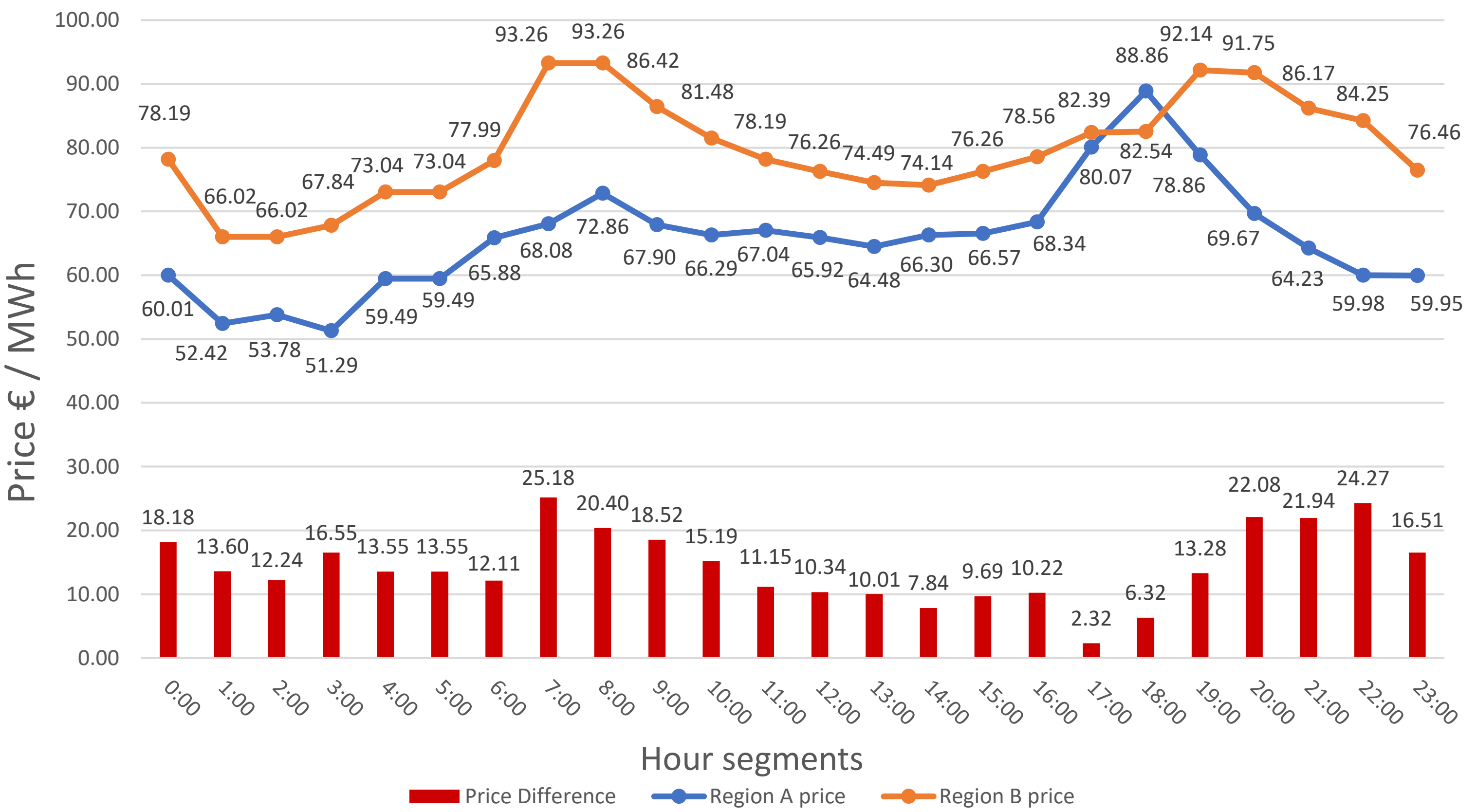

Figure 3.30 *Graphical presentation of region prices and price differences for each hour.*

3.3 100MW interconnection limit

In figure 3.30, the prices for each region are displayed pre- and post-market coupling. In this scenario, the capacity of the transmission line is limited to 100MW. It is clearly shown that region prices begin to converge. Region A has its price lower at all hour segments (except hour 18:00). Due to trading, price A increases, while price B takes a decrease.

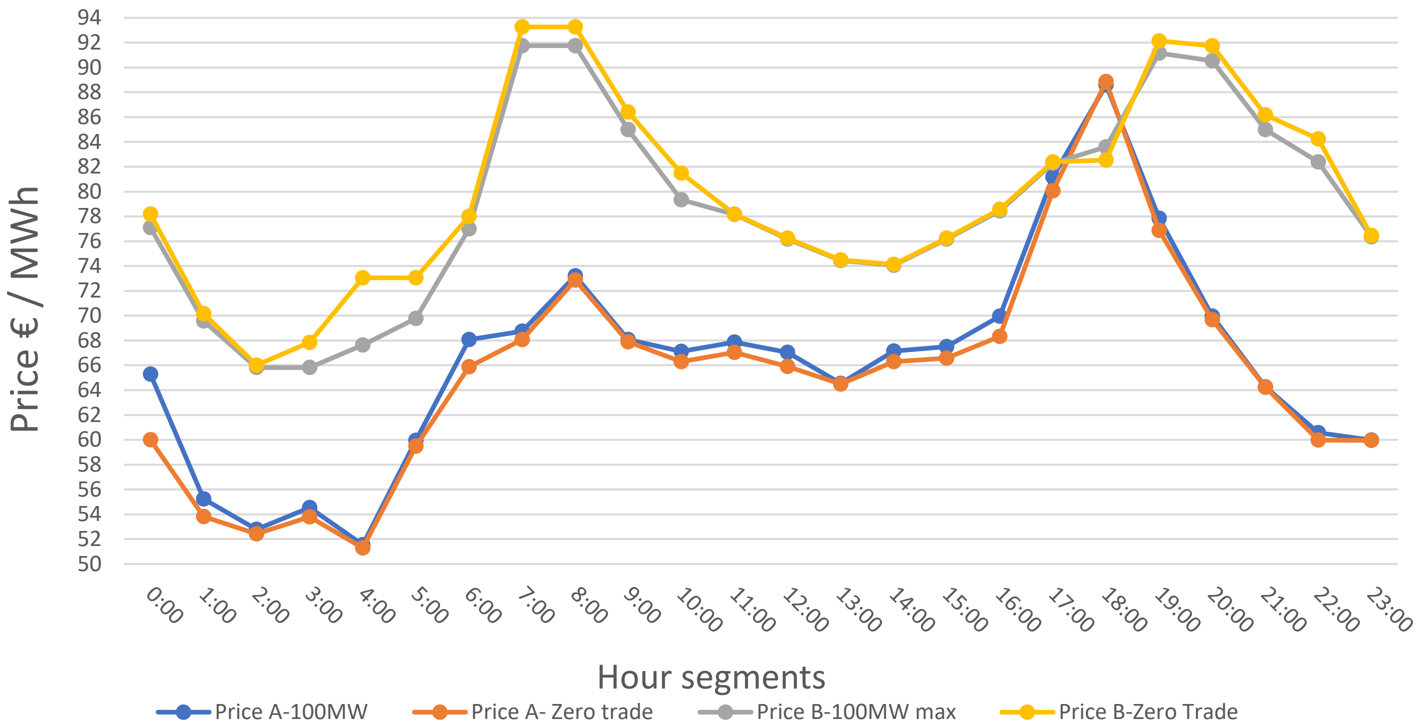

Figure 3.31 *Graphical presentation of region prices pre- and post-market coupling with 100MW max capacity.*

Following up in figure 3.31, the price changes for each region are shown. By inspecting the graph, region B gets the maximum benefit, with a 7.39% reduction in market price, while region A has its price increase by 8.82% at max. Overall, Region A gets an average 1.38% increase, while region B gets an average 1.32% decrease in market price.

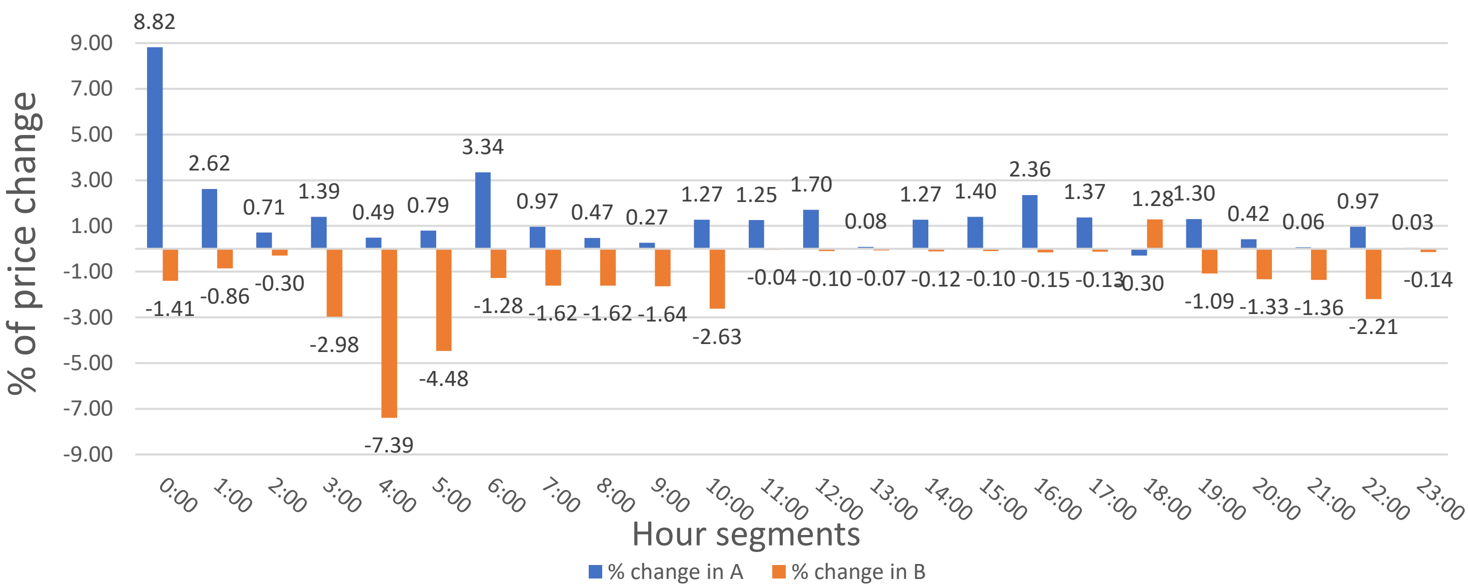

Figure 3.32 *Graphical presentation of region prices changes for each hour with 100MW max capacity.*

3.4 200MW interconnection limit

The 2nd scenario sets the maximum interconnection capacity at 200MW. As expected, higher available capacity causes prices to converge even more. Most noticeably, at hour 6:00, a full price convergence takes place. With prices 76.15€ and 76.45€ for region A and B respectively, the total trade capacity equals 196.8 MW. In this case, the interconnection is not fully used. Hour 17:00 is also worth noting. With prices 80.07€ and 81.21€ for A and B, prices to converge. However, in this case, the transmission line is fully used, so there is room for improvement.

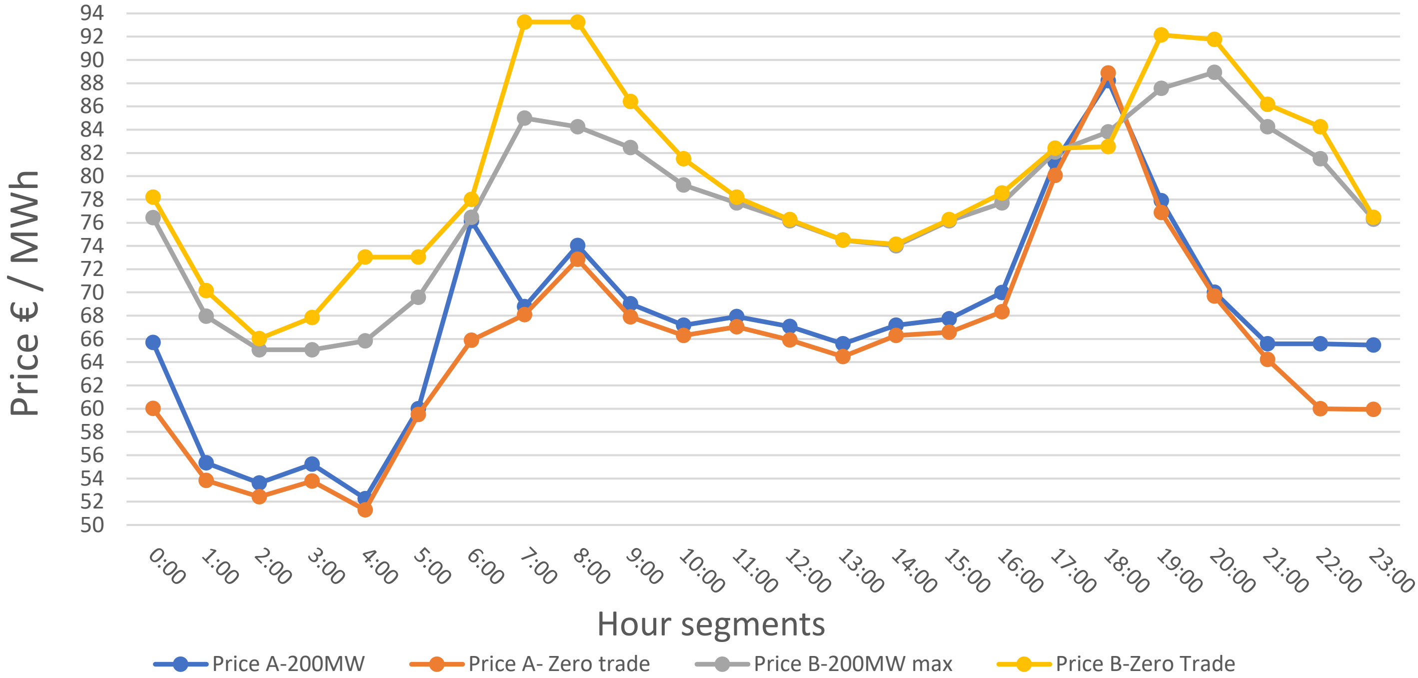

Figure 3.33 *Graphical presentation of region prices pre- and post-market coupling with 200MW max capacity.*

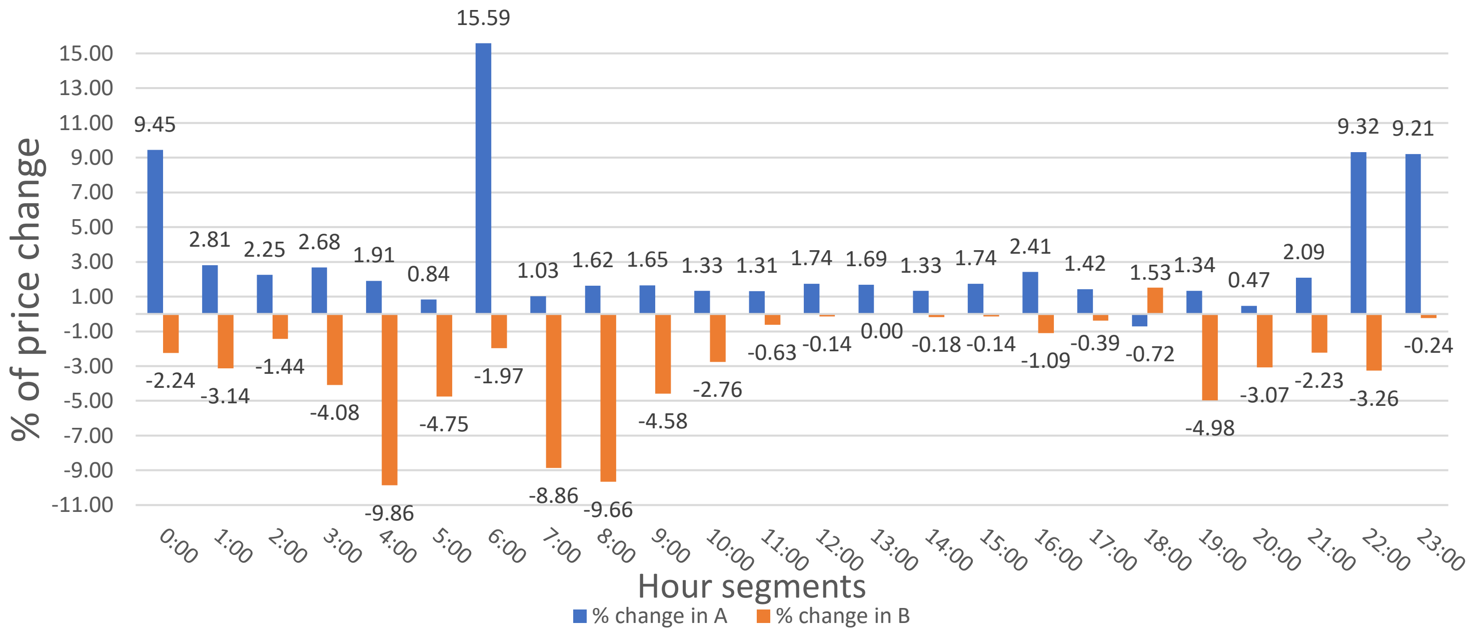

Figure 3.34 *Graphical presentation of region prices changes for each hour with 200MW max capacity.*

Similarly, in figure 3.32, price changes for each region are shown. Region B enjoys the biggest price decreases during hours 4:00 (-9.86%), 7:00 (-8.86%) and 8:00 (-9.66%), while Region A has the biggest increase during full-price convergence at hour 6:00 (+15.59%). Moderate increases also appear during hours 0:00 (+9.45%), 22:00 (+9.32%) and 23:00 (+9.21%). On average, region A experiences 3.1% price increase, while B gets 2.84% reduction in market price.

3.5 300MW interconnection limit

For the 3rd scenario, maximum transmission capacity is set at 300MW. As the capacity limit increases, more points of convergence appear, as shown in figure 3.34. Hour 6:00 still remains a fully coupled segment (196.8 MW traded). In this scenario, in two more hour segments the markets are fully coupled. At hour 17:00, the price of Region A is 81.27€ while B has a price of 81.47€, with a traded capacity at 290 MW. Additionally, at hour 19:00, the traded capacity is capped at 283.6 MW, despite prices for A and B are 77.94€ and 82.55€. The reason for this, is the profile of demand and supply bids for both regions. The simulator caps at 283.6 MW, because any further allocation of capacity results in $P_A>P_B$. This can also be

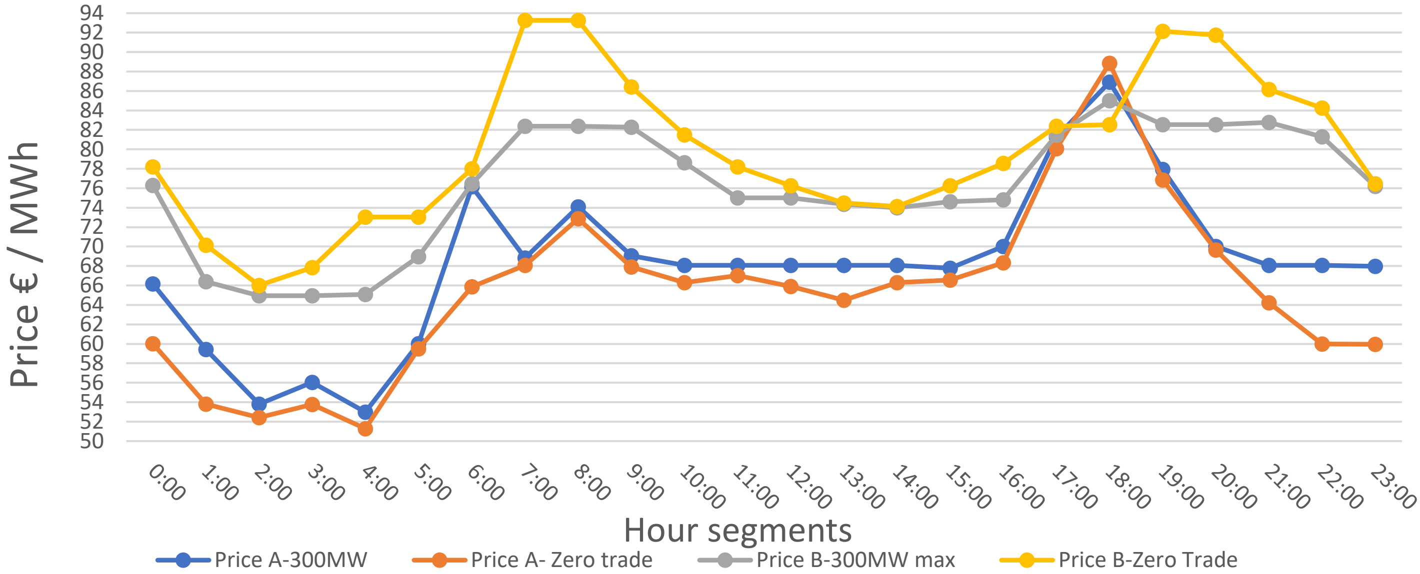

Figure 3.35 *Graphical presentation of region prices changes for each hour with 300MW max capacity.*

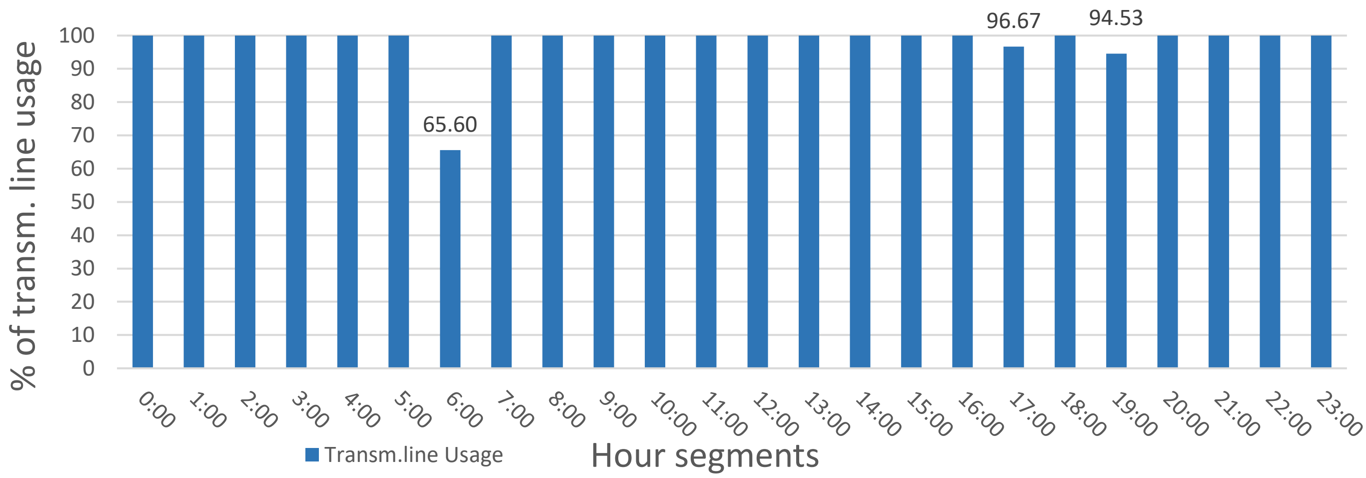

Figure 3.36 *Percentage usage of transmission line capacity for 300MW max capacity.*

shown in figure 3.35. The transmission line is used at 94.53% of maximum capacity. Along with hour 6:00 and 17:00, the two regions are fully-coupled during those three hour-segments. Any extra maximum capacity will not change market prices.

At this scenario, region A has an average increase in price by 4.41%, while region B gets an average reduction in price by 4.29%.

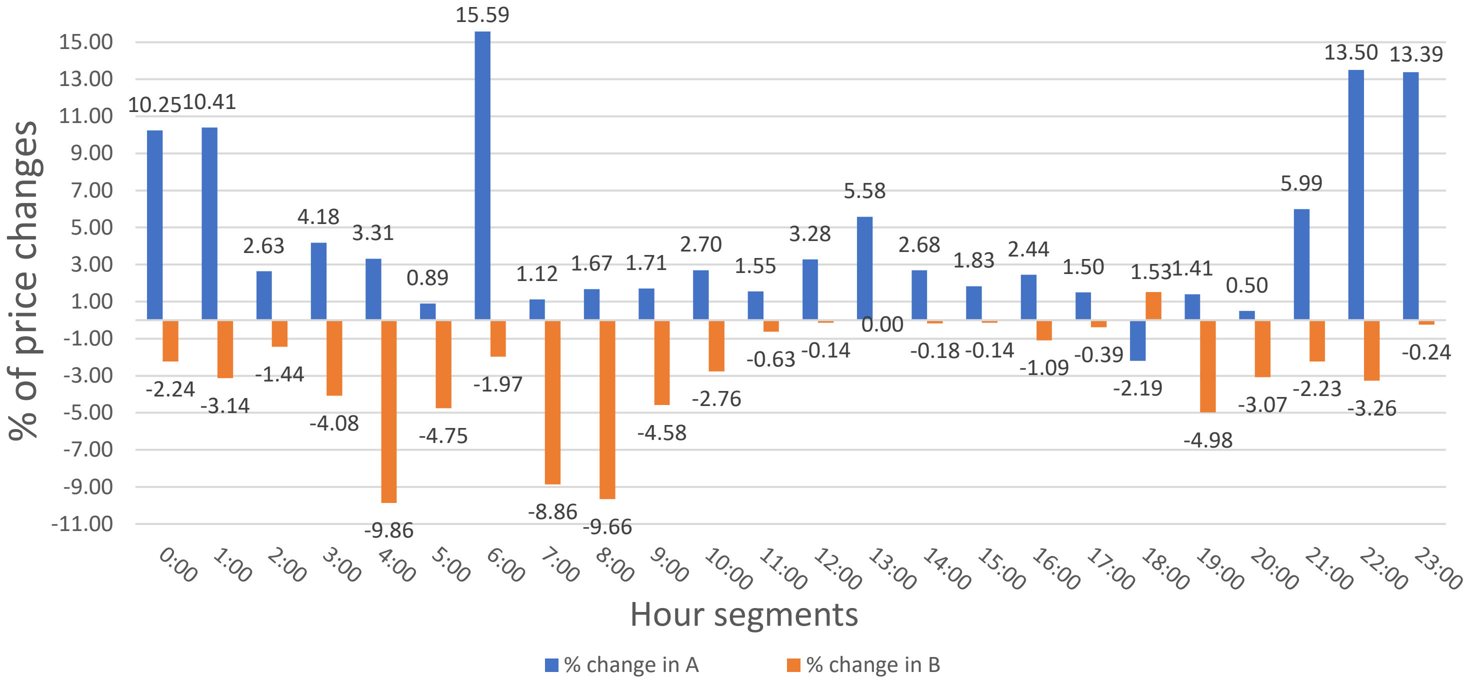

Figure 3.37 *Graphical presentation of region prices changes for each hour with 300MW max capacity.*

3.6 Unlimited transmission capacity

For the 4th scenario, the simulator sets the maximum transmission capacity to unlimited (practically, a very high value). At this case, the two markets will be fully-coupled, under two conditions: 1) price convergence or 2) available generation in a region. Prices for each region

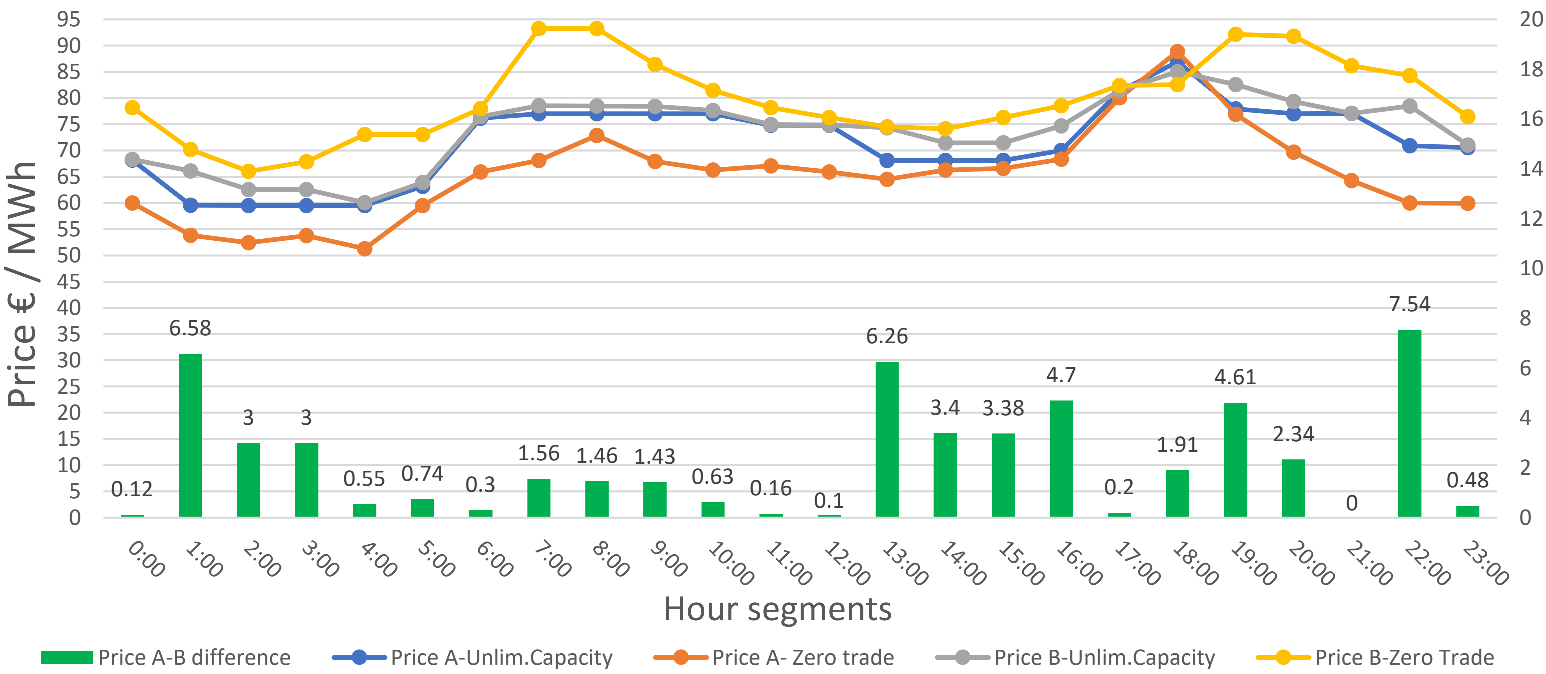

Figure 3.38 *Graphical presentation of region prices changes for each hour with unlimited line capacity.*

are shown in figure 3.37. The price difference between the two regions is shown in green. For the most part of hour segments, the two prices converge, with an average 2.26€/MWh difference. Highest discrepancies appear at hours 1:00, 13:00 and 22:00. By looking at figure 3.38, hours 1:00 and 22:00, region A which is the seller, has no available generation in order to further supply region B. In the case of hour 13:00, although the available generation is not exhausted, the bid profiles of supply and demand prevents the simulator from allocating further trade capacity that would result in $P_A > P_B$.

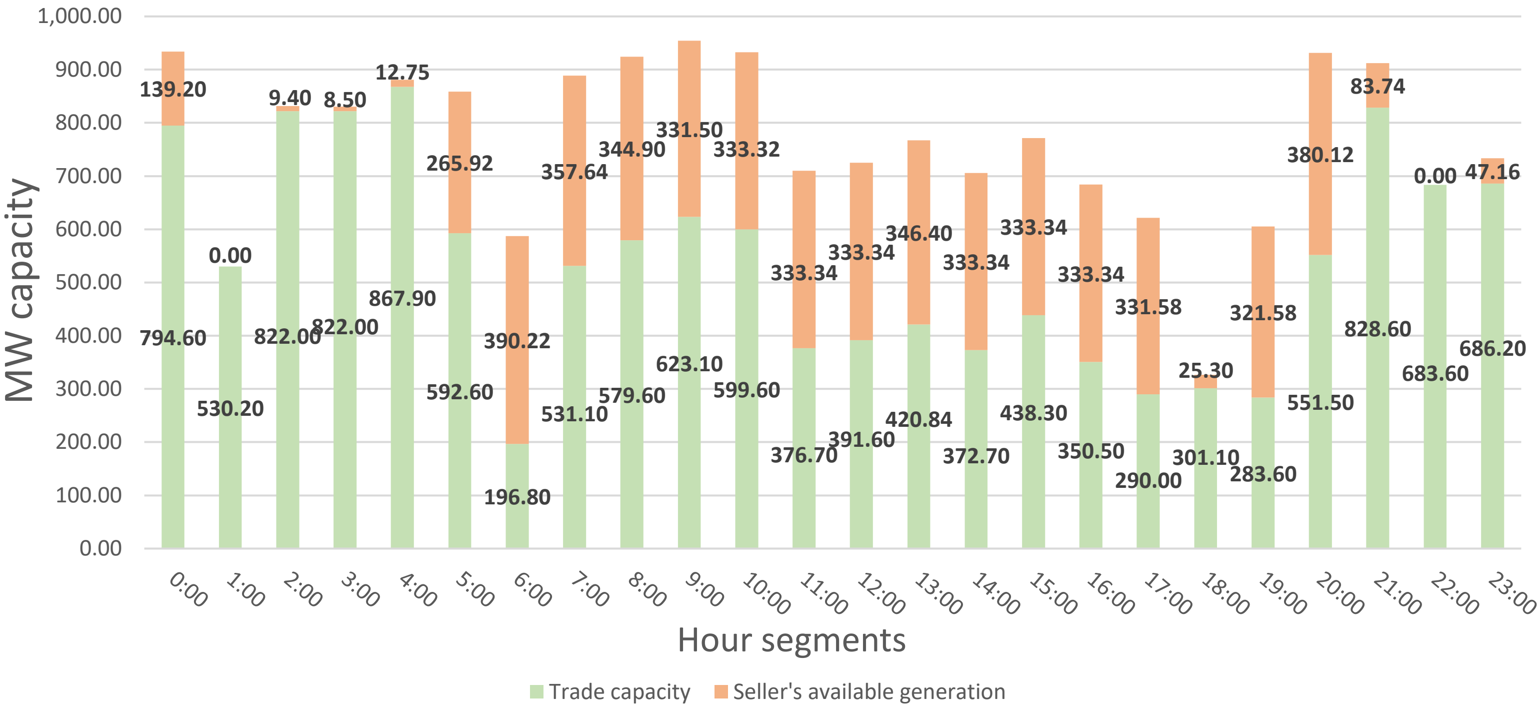

Figure 3.39 *Graphical presentation of calculated trade capacity and available generation of seller region for each hour.*

In figure 3.39, the pre- and post-coupling price differences are shown. For region A, the biggest price increase appears at hour 21:00, with a 19.99% increase and 828.6 MW of allocated capacity to trade. On the other hand, region B enjoys its higher price decrease during hour 4:00, with a 17.76% decrease, importing 867.9 MW capacity. On average, region A has 9.98% price increase in its market price, and is the seller in 23 out of 24 hour segments, while region B has 7.37% decrease in price and only sells during hour 18:00.

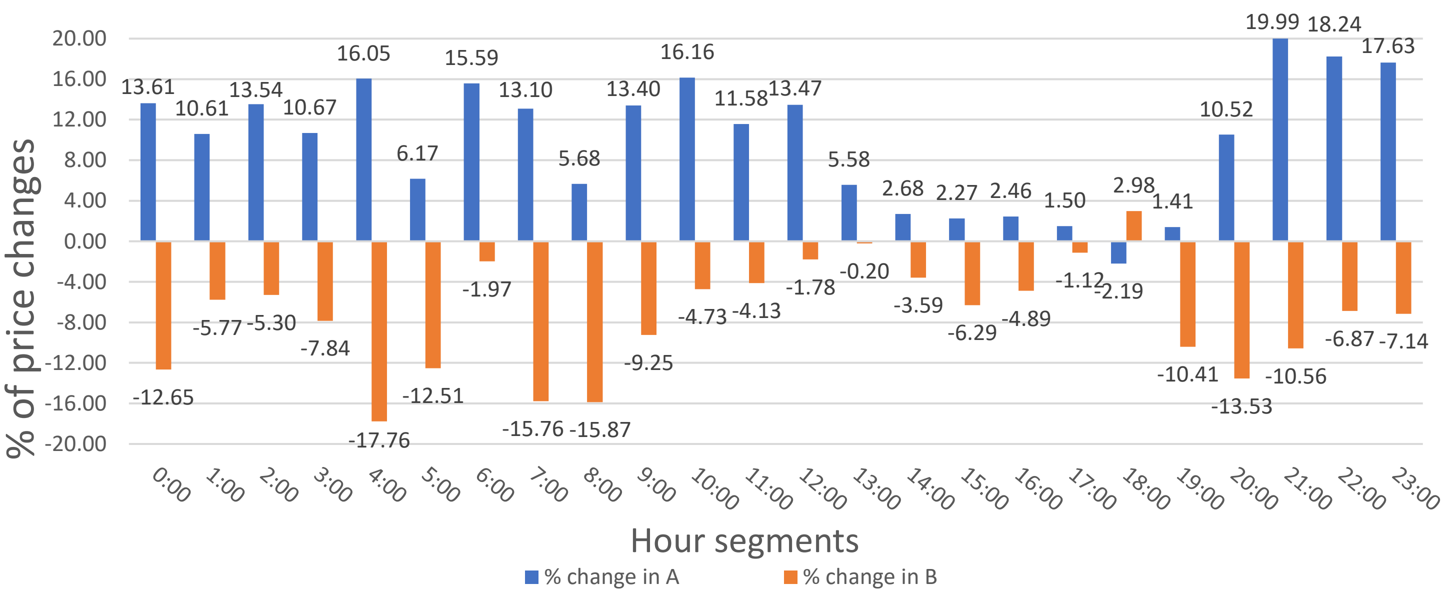

Figure 3.40 *Graphical presentation of region prices changes for each hour with unlimited maximum capacity.*

In table 3.2, market prices for each scenario for both regions A and B, are shown collectively. Region A mainly exports to region B, except hour 18:00. Therefore, market price A increases for most hour segments while price B declines.

	Region A					**Region B**				
Hour	**No Trade**	**100MW Cap**	**200MW Cap**	**300MW Cap**	**Unlimited Cap**	**No Trade**	**100MW Cap**	**200MW Cap**	**300MW Cap**	**Unlimited Cap**
0:00	*60.01*	65.30	65.68	66.16	68.18	*78.19*	77.09	76.44	76.30	68.30
1:00	*53.82*	55.23	55.33	59.42	59.53	*70.16*	69.56	67.96	66.39	66.11
2:00	*52.42*	52.79	53.60	53.80	59.52	*66.02*	65.82	65.07	64.95	62.52
3:00	*53.78*	54.53	55.22	56.03	59.52	*67.84*	65.82	65.07	64.95	62.52
4:00	*51.29*	51.54	52.27	52.99	59.52	*73.04*	67.64	65.84	65.08	60.07
5:00	*59.49*	59.96	59.99	60.02	63.16	*73.04*	69.77	69.57	68.97	63.90
6:00	*65.88*	68.08	76.15	76.15	76.15	*77.99*	76.99	76.45	76.45	76.45
7:00	*68.08*	68.74	68.78	68.84	77.00	*93.26*	91.75	85.00	82.39	78.56
8:00	*72.86*	73.20	74.04	74.08	77.00	*93.26*	91.75	84.25	82.39	78.46
9:00	*67.90*	68.08	69.02	69.06	77.00	*86.42*	85	82.46	82.28	78.43
10:00	*66.29*	67.13	67.17	68.08	77.00	*81.48*	79.34	79.23	78.63	77.63
11:00	*67.04*	67.88	67.92	68.08	74.80	*78.19*	78.16	77.70	75.00	74.96
12:00	*65.92*	67.04	67.07	68.08	74.80	*76.26*	76.18	76.15	75.00	74.90
13:00	*64.48*	64.53	65.57	68.08	68.08	*74.49*	74.44	74.49	74.35	74.34
14:00	*66.30*	67.14	67.18	68.08	68.08	*74.14*	74.05	74.01	73.99	71.48
15:00	*66.57*	67.50	67.73	67.79	68.08	*76.26*	76.18	76.15	74.63	71.46
16:00	*68.34*	69.95	69.99	70.01	70.02	*78.56*	78.44	77.70	74.82	74.72
17:00	*80.07*	81.17	81.21	81.27	81.27	*82.39*	82.28	82.07	81.47	81.47
18:00	*88.86*	88.59	88.22	86.91	86.91	*82.54*	83.6	83.80	85.00	85.00
19:00	*76.86*	77.86	77.89	77.94	77.94	*92.14*	91.14	87.55	82.55	82.55
20:00	*69.67*	69.96	70.00	70.02	77.00	*91.75*	90.53	88.93	82.55	79.34
21:00	*64.23*	64.27	65.57	68.08	77.07	*86.17*	85	84.25	82.77	77.07
22:00	*59.98*	60.56	65.57	68.08	70.92	*84.25*	82.39	81.50	81.30	78.46
23:00	*59.95*	59.97	65.47	67.98	70.52	*76.46*	76.35	76.28	76.19	71.00

Table 3.2 *Region A and B prices for each simulation scenario.*

4 Conclusions

Following the results from the four scenarios of the simulation, it is clear that electricity market-coupling of two regions can benefit both parties. However, achieving a “complete” coupling of markets depends on many different factors. At first, as shown in figure 3.38, the MW quantities required to achieve coupling, are of substantial size, compared to region load. Such high quantities require robust grid infrastructure, and therefore, huge investments in upgrading transmission lines and electrical equipment. Once the physical restrictions of the infrastructure are no longer an issue, the bid profiles and behavior of generator and retailers heavily affects the convergence of market prices. As mentioned above in the 3rd scenario, despite the maximum capacity set at 300MW, only 65,60% of the transmission capacity is used. In this case, though, the set of bids that were used as input refer to each region, in a state of inactive coupling. Therefore, bid strategies are expected to differ, if market participants have the information that enough maximum capacity is available through trade and a price incentive exists. Furthermore, as shown in figure 3.38, the available generation of seller plays an important role. In cases where available generation is exhausted, there is room for additional production. It is an incentive for existing generators to increase their units' production, insert more generating units in the grid, or even invest in construction of new ones. On the other hand, regions that struggle or lack enough generation in their market, can take advantage of coupling to meet their demand load.

Overall, comparing the output data of all scenarios, coupling two markets results in convergence of their market prices. Producers in selling regions would see their profits increased, as exporting energy increases the market price. On the contrary, regions importing energy would see their market price decrease. This results in reduced cost for electricity consumers. However, exporting regions would always experience reduced consumer welfare, due to increase market prices.

In the present market coupling simulation, the estimated system load by the System Operator for each hour is not taken into account. If this information is included in the process, it would alter each region's market equilibrium, since the market will be cleared at supplier price once the estimated MW quantity is satisfied.

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